U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

NUREG-2191, Volume 2
Revision 1

Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report

Draft Report for Comment

Office of Nuclear Reactor Regulation

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Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report

Draft Report for Comment

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Office of Nuclear Reactor Regulation

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Mail comments to: Houman Rasouli, Director, Program Management, Announcements and Editing Branch (PMAE), Office of Administration, Mail Stop: TWFN-7-A-60M, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

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Please be aware that any comments that you submit to the NRC will be considered a public record and entered in the Agencywide Documents Access and Management System (ADAMS). Do not provide information you would not want to be publicly available.

ABSTRACT

This document provides guidance on the content of applications for renewal of the initial renewed operating license. The initial renewed operating license is the first renewed license issued under Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," after either supersession or the expiration of the original operating license issued under either 10 CFR Part 50 or Part 52 following the completion of construction under a construction permit issued under Part 50, or a combined license issued under Part 52. In this guidance document, the renewal of the initial renewed operating license is referred to as "subsequent license renewal" (SLR). Draft NUREG–2191, Revision 1, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Draft Report for Comment" (GALL-SLR Report, Revision 1, GALL-SLR Report, or simply GALL-SLR) provides guidance for SLR applicants. The GALL-SLR Report contains the U.S. Nuclear Regulatory Commission (NRC) staff's generic evaluation of plant aging management programs (AMPs) and establishes the technical basis for their adequacy. The GALL-SLR Report contains recommendations about specific areas for which existing AMPs should be augmented for SLR. An applicant may reference this report in an SLR application to demonstrate that the AMPs at the applicant's facility correspond to those described in the GALL-SLR Report. If an applicant credits an AMP in the GALL-SLR Report, it is incumbent on the applicant to ensure that the conditions and operating experience at the plant are bounded by the conditions and OE for which the GALL-SLR Report program was evaluated. If these bounding conditions are not met, it is incumbent on the applicant to address any additional aging effects and augment the AMPs for SLR. For AMPs that are based on the GALL-SLR Report, the NRC staff will review and verify whether the applicant's AMPs are consistent with those described in the GALL-SLR Report, including applicable plant conditions and operating experience. The focus of the NRC staff's review of an SLR application is on the AMPs that an applicant has enhanced to be consistent with the GALL-SLR Report, the AMPs for which the applicant has taken an exception to the program described in the GALL-SLR Report, and plant-specific AMPs not described in the GALL-SLR Report.

This document is a companion document to Draft NUREG–2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants, Draft Report for Comment" (SRP-SLR), Revision 1, that provides guidance to NRC staff on the review of SLR applications. The guidance in this document is for the use of future applicants for SLR. The NRC does not intend to impose the guidance in this document on current holders of an initial operating license. However, this document encompasses all of the guidance applicable to initial license renewal. Accordingly, both current holders of initial operating licenses as well as future applicants for initial license renewal may voluntarily choose to reference an AMP in the GALL-SLR Report in their applications. However, such applicants should inform the NRC that they plan to demonstrate consistency with the GALL-SLR Report.

Drafts of GALL-SLR Report, Revision 0, and the SRP-SLR, Revision 0, were published for public comment in December 2015, and the comment period ended on February 29, 2016. The staff received more than 300 pages of comments from interested stakeholders. The comments were reviewed and dispositioned by the staff, and documented in NUREG-2222, "Disposition of Public Comments on the Draft Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG–2192" (Agencywide Documents Access and Management System [ADAMS] Accession No. ML17362A143), in December 2017. The disposition of the comments was published in final NUREG-2191, Revision 0, (GALL-SLR Report, Rev. 0) (ADAMS Accession Nos. ML17187A031, and ML17187A204, for Volumes 1 and 2 respectively) in July 2017. The

companion document final SRP-SLR, Revision 0 (SRP-SLR, Rev. 0) (ADAMS Accession No. ML17188A158) was also issued in July 2017. The staff also published NUREG-2221, "Technical Bases for Changes in the Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG–2192" (Technical Basis Document) (ADAMS Accession No. ML17362A126) in December 2017, that documented all the technical changes made to the license renewal guidance documents for SLR (i.e., for operation from 60 years to 80 years), along with the technical bases for the changes.

Subsequently, the NRC staff determined that certain revisions and updates to these guidance documents are warranted. These revisions and updates are presented in draft Revision 1 to the SRP-SLR and draft Revision 1 to the GALL-SLR. Comments on the revised documents will be considered, as appropriate, in the final versions of these documents. A draft supplement to the Technical Basis Document (NUREG-2221) was also published.

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This NUREG provides voluntary guidance for implementing the mandatory information collections in 10 CFR Part 51 that are subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.). These information collections were approved by the Office of Management and Budget (OMB) under control number 3150-0021. Send comments regarding these information collections to the FOIA, Library, and Information Collections Branch (T6A10M), U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001, or by email to Infocollects.Resource@nrc.gov, and to the OMB reviewer at: OMB Office of Information and Regulatory Affairs (3150-0021). Attn: Desk Officer for the Nuclear Regulatory Commission, 725 17th Street NW, Washington, DC 20503; email: oira_submission@omb.eop.gov.

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ABBREVIATIONS

AC	alternating current
ACAR	aluminum conductor aluminum alloy reinforced
ACSR	aluminum conductor steel reinforced
ADAMS	Agencywide Documents Access and Management System
AEA	Atomic Energy Act
AERM	aging effect requiring management
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction
Al	Aluminum
AMP	aging management program
AMR	aging management review
ASME	American Society of Mechanical Engineers
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ASTM	ASTM International (formerly American Society for Testing and Materials)
AWG	American wire gauge
B&W	Babcock & Wilcox
BWR	boiling water reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CASS	cast austenitic stainless steel
CCCW	closed-cycle cooling water
CE	Combustion Engineering
CEA	control element assembly
CFR	*Code of Federal Regulations*
CFRP	carbon fiber reinforced polymer
CLB	current licensing basis
CRD	control rod drive
CRGT	control rod guide tube
CSE	copper/copper sulfate reference electrode
CUF	cumulative usage factor
CVCS	chemical and volume control system
DOE	U.S. Department of Energy
DOR	Division of Operating Reactors
ECT	eddy current testing
ECCS	emergency core cooling system
ECW	Emergency Chilled Water
EDG	emergency diesel generator
EMDA	Expanded Materials Degradation Assessment
EPDM	ethylene propylene diene monomer

EPR	ethylene-propylene rubber
EPRI	Electric Power Research Institute
EPT	ethylene propylene terpolymer
ETFE	ethylene tetrafluoroethylene
EQ	environmental qualification

FAC	flow-accelerated corrosionFD flow distributor
FERC	Federal Energy Regulatory Commission
FOIA	Freedom of Information Act
FRN	*Federal Register* notice
FSAR	Final Safety Analysis Report
FW	feedwater

GALL	Generic Aging Lessons Learned
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GL	generic letter

HDPE	high-density polyethylene
HPCI	high-pressure coolant injection
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning

I&E	inspection and evaluation
IAEA	International Atomic Energy Agency
IASCC	irradiation-assisted stress corrosion cracking
ICMH	incore-monitoring housing
ID	inside diameter
IE	irradiation embrittlement
IESRC	irradiation-enhanced stress relaxation or creep
IGA	intergranular attack
IGSCC	intergranular stress corrosion cracking
IS	inside surface
IAEA	International Atomic Energy Agency
IASCC	irradiation-assisted stress corrosion cracking

ICI	incore instruments
ID	inside diameter
IGSCC	intergranular stress corrosion cracking
IMI	incore monitoring instrumentation
ISG	interim staff guidance
ISI	inservice inspection
ISP	integrated surveillance program

LFET	low-frequency electromagnetic technique

LOCA	loss of coolant accident
LPCI	low-pressure coolant injection
LPSI	low-pressure safety injection
LRA	license renewal application
LR-ISG	license renewal interim staff guidance
LRT	leak rate test
LTOP	low temperature overpressure protection
LTS	lower thermal shield
LWR	light water reactor
MC	metal containment
MEB	metal enclosed bus
MIC	microbiologically influenced corrosion
MRP	Materials Reliability Program
MRV	minimum required value
MS	main steam
NACE	National Association of Corrosion Engineers
NDE	nondestructive examination
NEA	Nuclear Energy Agency
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NPP	nuclear power plant
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
OCCW	open-cycle cooling water
OE	operating experience
OMB	Office of Management and Budget
PH	precipitation-hardening (or hardened)
PLL	predicted lower limit
PTFE	polytetrafluoroethylene elastomer
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PWR	pressurized water reactor
QA	quality assurance
RCIC	reactor core isolation cooling
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RES	Office of Nuclear Regulatory Research

RHR	residual heat removal
RPV	reactor pressure vessel
RT_{NDT}	reference nil-ductility temperature
RV	reactor vessel
RVI	reactor vessel internal
RWCU	reactor water cleanup
SBO	station blackout
SCs	structures and components
SCC	stress corrosion cracking
SDC	shutdown cooling
SER	Safety Evaluation Report
SFP	spent fuel pool
SG	steam generator
SIR	silicone rubber
SLC	standby liquid control
SLR	subsequent license renewal
SLRA	subsequent license renewal application
SOC	Statements of Consideration
SOER	significant operating experience report
SRM	source range monitor
SRM	staff requirements memorandum
SRP	Standard Review Plan
SRP-SLR	Standard Review Plan for Review of Subsequent License Renewal
SS	stainless steel
SSCs	systems, structures, and components
SSHT	surveillance specimen holder tube
TLAA	time-limited aging analysis
TR	Technical Report
TS	technical specification
UCB	upper core barrel
UHS	ultimate heat sink
USACE	U.S. Army Corps of Engineers
USAS	United States of America Standards
USE	upper-shelf energy
UT	ultrasonic testing
UTS	Unified Thread Standard
UV	ultraviolet
XLPE	cross-linked polyethylene

INTRODUCTION

Draft NUREG–2191, Revision 1, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR), Draft Report for Comment” (GALL-SLR Report, Revision. 1, GALL-SLR Report, or simply GALL-SLR), is referenced as a technical basis document in Draft NUREG–2192, Revision 1, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants, Draft Report for Comment” (SRP-SLR, Revision 1, or simply SRP-SLR). The GALL-SLR Report lists generic aging management reviews of systems, structures, and components (SSCs) that may be in the scope of subsequent license renewal applications (SLRAs) and identifies aging management programs (AMPs) that are determined to be acceptable for managing the effects of aging on SSCs in the scope of license renewal, as required by Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.” If an applicant credits an AMP described in the GALL-SLR Report in the SLRA, the applicant should ensure that the conditions and operating experience at the plant are bounded by the conditions and operating experience for which the GALL-SLR Report program was evaluated. If these bounding conditions are not met, the applicant should address any additional aging effects and augment the AMPs for subsequent license renewal. If an SLRA references the approach described in the GALL-SLR Report as the approach used for managing the aging effect(s), the U.S. Nuclear Regulatory Commission staff will use the GALL-SLR Report as a basis for the SLRA assessment, consistent with guidance specified in the SRP-SLR.

BACKGROUND

The Atomic Energy Act of 1954, as amended, allows the U.S. Nuclear Regulatory Commission (NRC) to issue licenses for commercial nuclear power reactors to operate for up to 40 years. The NRC regulations permit these licenses to be renewed beyond the initial 40-year term for an additional period of time, limited to 20-year increments per renewal, based on the results of an assessment conducted to determine whether the nuclear facility can continue to operate safely during the proposed period of extended operation. There are no limitations in the Atomic Energy Act or the NRC regulations restricting the number of times a license may be renewed.

The focus of license renewal, as described in Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, is to identify aging effects that could impair the ability of systems, structures, and components within the scope of license renewal to perform their intended functions, and to demonstrate that these effects will be adequately managed during the period of extended operation. The regulatory requirements for both initial and subsequent license renewal (SLR) are established by 10 CFR Part 54. To address the unique aspects of material aging and degradation that would apply to SLR (e.g., to permit plants to operate for up to 80 years), the Office of Nuclear Reactor Regulation requested support from the Office of Nuclear Regulatory Research to develop technical information to evaluate the feasibility of SLR. The Office of Nuclear Regulatory Research has memoranda of understanding with both the U.S. Department of Energy (DOE) and the Electric Power Research Institute to cooperate in conducting nuclear safety research related to long-term operations beyond 60 years. Under these memoranda, the NRC and the DOE held two international conferences, in 2008 and 2011, on reactor operations beyond 60 years. In May 2012, the NRC and the DOE also co-sponsored the Third International Conference on Nuclear Power Plant Life Management for Long-Term Operations, organized by the International Atomic Energy Agency (IAEA). In February 2013 and February 2015, the Nuclear Energy Institute held a forum on long-term operations and SLR. These conferences laid out the technical issues that would need to be addressed to provide assurance of safe operation beyond 60 years.

Based on the information gathered from these conferences and forums, and from other sources over the past several years, the most significant technical issues identified as challenging operation beyond 60 years are reactor pressure vessel embrittlement; irradiation-assisted stress corrosion cracking of reactor vessel internals; concrete structures and containment degradation; and electrical cable environmental qualification, condition monitoring and assessment. Throughout this process, the NRC staff has emphasized that it is the industry’s responsibility to resolve these and other issues to provide the technical bases to ensure safe reactor operation beyond 60 years.

The NRC, in cooperation with the DOE, completed the Expanded Materials Degradation Assessment (EMDA) in 2014 (Agencywide Documents Access and Management System [ADAMS] Accession Nos. ML14279A321, ML14279A331, ML14279A349, ML14279A430, and ML14279A461). The EMDA uses an expert elicitation process to identify materials and components that could be susceptible to significant degradation during operation beyond 60 years. The EMDA covers the reactor vessel, primary system piping, reactor vessel internals, concrete, and electrical cables and qualification. The NRC staff used the results of the EMDA to identify gaps in the current technical knowledge or issues not being addressed by planned industry or DOE research, and to identify aging management programs (AMPs) that will require modification for SLR.

On May 9, 2012 (ADAMS Accession No. ML12158A545) and subsequently on November 1, 13, and 14, 2012, the NRC staff and interested stakeholders met to discuss issues and receive comments for consideration for SLR. The staff's resolution of and response to these public comments are available in the staff's memo dated September 12, 2016 (ADAMS Accession No. ML16194A222).

In addition to working with external stakeholders, the NRC staff conducted AMP effectiveness audits at three units that were at least 2 years into the period of extended operation. The purpose of these information-gathering audits was to better understand how licensees are implementing the license renewal AMPs, in terms of both the findings and the effectiveness of the programs, and to develop recommendations for updating license renewal guidance. The NRC staff used the information gathered from these audits to update the SLR guidance based on the staff's experience with the aging management activities during the first license renewals. A summary of the first two AMP effectiveness audits can be found in the May 2013 report, "Summary of Aging Management Program Effectiveness Audits to Inform Subsequent License Renewal: R.E. Ginna nuclear power plant and Nine Mile Point Nuclear Station, Unit 1" (ADAMS Accession No. ML13122A007). The summary of the third audit can be found in the August 5, 2014, report, "H.B. Robinson Steam Electric Plant, Unit 2, Aging Management Program Effectiveness Audit" (ADAMS Accession No. ML14017A289). In addition, on June 15, 2016, the staff issued the Technical Letter Report, "Review of Aging Management Programs: Compendium of Insight from License Renewal Applications and from AMP Effectiveness Audits Conducted to Inform Subsequent License Renewal Guidance Documents" (ADAMS Accession No. ML16167A076), which provides the staff's observations derived from reviewing license renewal applications and conducting the AMP effectiveness audits.

The NRC staff reviewed domestic operating experience (OE) as reported in licensee event reports and NRC generic communications related to failures and degradation of passive components. Similarly the NRC staff reviewed the following international OE databases: (1) International Reporting System, jointly operated by the IAEA; (2) IAEA's International Generic Ageing Lessons Learned Programme; (3) Organisation for Economic Co-operation and Development/Nuclear Energy Agency Component Operational Experience and Degradation and Ageing Programme database; and (4) Organisation for Economic Co-operation and Development/Nuclear Energy Agency Cable Aging Data and Knowledge database.

The NRC staff reviewed the results from AMP audits, findings from the EMDA, domestic and international OE, and public comments to identify technical issues that need to be considered when assuring the safe operation of NRC-licensed nuclear power plants. By letter dated August 6, 2014 (ADAMS Accession No. ML14253A104), the Nuclear Energy Institute documented the industry's views about and recommendations for updating NUREG–1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report," (ADAMS Accession No. ML103490041) (GALL Report, Rev. 2) and NUREG–1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," (ADAMS Accession No. ML103490036) (SRP-LR, Rev 2.) to support SLR. Between fiscal years 2014 and 2015, the NRC staff reviewed the comments and recommendations and drafted NUREG–2191, Revision 0, "Generic Aging Lessons Learned for Subsequent License Renewal Report" (GALL-SLR Report Rev. 0) to ensure that sufficient guidance was in place to support review of an SLR application in 2018 or 2019.

The staff requirements memorandum on SECY-14-0016, "Ongoing Staff Activities to Assess Regulatory Considerations for Power Reactor Subsequent License Renewal" (ADAMS Accession No. ML14241A578), directed the staff to continue to update the license renewal guidance, as needed, to provide additional clarity about the implementation of the license renewal regulatory framework. The staff requirements memorandum also directed the staff to keep the Commission informed about the progress made in resolving the following technical issues related to SLR: (1) reactor pressure vessel neutron embrittlement at high fluence, (2) irradiation-assisted stress corrosion cracking of reactorvessel internals and primary system components, (3) concrete and containment degradation, and (4) electrical cable qualification and condition assessment. In addition, the staff requirements memorandum directed that the staff should keep the Commission informed regarding the staff's readiness to accept an application and any further need for regulatory process changes, rulemaking, or research.

During the staff's consideration of revisions to 10 CFR Part 54, changes to the License Renewal Rule were considered to address the provisions of 10 CFR 50.54(hh)(2) regarding guidance and strategies to maintain and restore core cooling, containment, and spent fuel cooling capabilities under the circumstances associated with the loss of large areas of the plant due to explosions or fires. After discussions with stakeholders and the public, it was concluded that these issues need not be addressed in the License Renewal Rule because emergency preparedness equipment is not identified in 10 CFR 54.4(a)(3). The 1995 *Federal Register* notice for the final license renewal rule, 60 FR 22461, 22468 states:

> Regarding systems, structures, and components required to make protective action recommendations, the Commission thoroughly evaluated emergency planning considerations in the previous license renewal rulemaking. These evaluations and conclusions are still valid and can be found in the [*Statements of Consideration*] SOC for the previous license renewal rule (56 FR 64943 at 64966). Therefore, the Commission concludes that systems, structures, and components required for emergency planning, unless they meet the scoping criteria in §54.4, should not be the focus of a license renewal review.

Further, even if this equipment is within the scope of license renewal, that does not necessarily mean that it is subject to aging management review based on the existing rule because only passive, long-lived structures and components are subject to an aging management review. Further, this is not an issue specific to SLR and is inconsistent with the first principle of license renewal (i.e., "….with the exception of age-related degradation and possibly a few other issues related to safety only during extended operation of nuclear power plants, the existing regulatory process is adequate to ensure that the licensing bases of all currently operating plants provide and maintain an acceptable level of safety so that operation will not be inimical to public health and safety or common defense and security"). Therefore, there is no need to address 10 CFR 50.54(hh) and diverse and flexible mitigation capability equipment in the License Renewal Rule.

On July 14, 2017 (82 FR 32588), the NRC announced the issuance and availability of the following final SLR guidance documents:

- Final NUREG–2191, Revision 0, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," (GALL-SLR Report, Rev. 0) (ADAMS Accession Nos. ML17187A031, and ML17187A204, for Volumes 1 and 2 respectively), and
- Final NUREG–2192, Revision 0, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants." (SRP-SLR, Rev. 0) (ADAMS Accession No. ML17188A158).

The GALL-SLR Report, Rev. 0, (Accession Nos. ML17187A031, and ML17187A204, for Volumes 1 and 2 respectively), and the companion document SRP-SLR, Revision 0 (SRP-SLR, Rev. 0) (Accession No. ML17188A158) were both issued in July 2017. The GALL-SLR Report, Rev. 0, includes the NRC staff's resolutions of License Renewal Interim Staff Guidance (LR-ISG) from 2011 through 2016. Under the ISG process, the NRC staff, industry, or stakeholders can propose a change to certain license renewal guidance documents. The NRC staff evaluates the issue, develops the proposed ISG, issues it for public comment, evaluates any comments received, and, if necessary, issues the final ISG.

The ISG is then used until the NRC staff incorporates the revised guidance into a formal license renewal guidance document revision. The ISGs addressed in the GALL-SLR Report, Rev. 0, are listed as follows:

- LR-ISG-2011-01: "Aging Management of Stainless Steel Structures and Components in Treated Borated Water, Revision 1." ADAMS Accession No. ML12286A275. December 18, 2012.
- LR-ISG-2011-02: "Aging Management Program for Steam Generators." ADAMS Accession No. ML11297A085. November 21, 2011.
- LR-ISG-2011-03: "Generic Aging Lessons Learned (GALL) Report Revision 2 AMP XI.M41," "Buried and Underground Piping and Tanks." ADAMS Accession No. ML12138A296. July 26, 2012.
- LR-ISG-2011-04: "Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors." ADAMS Accession No. ML12270A436. May 28, 2013.
- LR-ISG-2011-05: "Ongoing Review of Operating Experience." ADAMS Accession No. ML12044A215. March 9, 2012.
- LR-ISG-2012-01: "Wall Thinning Due to Erosion Mechanisms." ADAMS Accession No. ML12352A057. April 25, 2013.
- LR-ISG-2012-02: Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation. ADAMS Accession No. ML13227A361. November 14, 2013.
- LR-ISG-2013-01: "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks." ADAMS Accession No. ML14225A059. November 6, 2014.
- LR-ISG-2015-01: "Changes to Buried and Underground Piping and Tank Recommendations." ADAMS Accession No. ML15308A018. January 28, 2016.
- LR-ISG-2016-01: "Changes to Aging Management Guidance for Various Steam Generator Components." ADAMS Accession No. ML16237A383. November 30, 2016.

Subsequent to the issuance of GALL-SLR Report, Rev. 0, and SRP-SLR, Rev. 0, several more ISGs, each specifically referred to as Subsequent License Renewal Interim Staff Guidance (SLR-ISG), were proposed due to new or updated industry guidance, codes, or standards; relevant plant operating experience; incorporation of lessons learned from completed SLR application reviews; development of new aging management programs or aging management review items, and identification of required corrections and clarifications to the guidance. Additional updates of similar category were identified subsequent to SLR-ISG issuance. The staff determined that a revision (Revision 1) to the GALL-SLR Report, Rev. 0, and SRP-SLR, Rev. 0, was warranted, to directly incorporate these additional updates and the issued SLR-ISGs listed below:

- SLR-ISG-2021-01-PWRVI: “Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors of Subsequent License Renewal Guidance.” ADAMS Accession No. ML20217L203. January 8, 2021.
- SLR-ISG-2021-02-MECHANICAL: “Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance.” ADAMS Accession No. ML20181A434. February 18, 2021.
- SLR-ISG-2021-03-STRUCTURES: “Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance.” ADAMS Accession No. ML20181A381. February 18, 2021.
- SLR-ISG-2021-04-ELECTRICAL: “Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance.” ADAMS Accession No. ML20181A395. February 18, 2021.

OVERVIEW OF THE GENERIC AGING LESSONS LEARNED FOR SUBSEQUENT LICENSE RENEWAL REPORT EVALUATION PROCESS

The Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (GALL-SLR Report) contains 11 chapters and 2 appendices. Most of the chapters contain summary descriptions and tabulations of evaluations of aging management programs (AMPs) for a large number of structures and components (SCs) in major plant systems found in light-water reactor nuclear power plants. The major plant systems include the containment structures (Chapter II), SC supports (Chapter III), reactor vessel internals and reactor coolant system (Chapter IV), engineered safety features (Chapter V), electrical components (Chapter VI), auxiliary systems (Chapter VII), and steam and power conversion system (Chapter VIII).

Chapter I of the GALL-SLR Report addresses the application of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) for subsequent license renewal (SLR). Chapter IX contains the description of a selection of standard terms used in the GALL-SLR Report. Chapter X contains examples of AMPs that may be used to demonstrate the acceptance of time-limited aging analyses in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 54.21(c)(1)(iii). Chapter XI contains the AMPs for the mechanical, structural, and electrical components. The appendices of the GALL-SLR Report address quality assurance for AMPs and operating experience.

The evaluation process for the AMPs and the application of the GALL-SLR Report is described in this document. The aging management review items for the GALL-SLR Report are presented in tabular format as described in Table 1. Table 1 describes the information presented in each column of the tables in Chapters II through VIII in this report.

Table 1 Aging Management Review Column Heading Descriptions

Column Heading	Description
New (N), Modified (M), Deleted (D), Edited (E) Item	Identifies the item as new to the GALL-SLR Report, Revision 1; modified from GALL-SLR Report, Revision 0; deleted from GALL-SLR Report, Revision 0; edited from GALL-SLR Report, Revision 0; or if blank, as unchanged from GALL-SLR Report, Revision 0.
Item	Identifies a unique number for the item (i.e., VII.G.A-91). The first part of the number indicates the chapter and aging management review system (e.g., VII.G is in the auxiliary systems, fire protection system), and the second part is a unique chapter-specific identifier within a chapter (e.g., A–91 for auxiliary systems).
Standard Review Plan (SRP) Item (Table, ID)	For each row in the subsystem tables, this item identifies the corresponding row identifier from the SRP-SLR to provide the crosswalk to the SRP system table items.
Structure and/or Component	Identifies the structure or components to which the row applies.
Material	Identifies the material of construction. See Chapter IX.C of this report for further information.
Environment	Identifies the environment applicable to this row. See Chapter IX.D of this report for further information.

Column Heading	Description
Aging Effect/ Mechanism	Identifies the applicable aging effect and mechanism(s). See Chapters IX.E and IX.F of this report for more information about applicable aging effects/mechanisms.
Aging Management Program (AMP)/TLAA	Identifies an AMP/TLAA found acceptable for adequately managing the effects of aging. See Chapters X and XI of this report.
Further Evaluation	Identifies whether a further evaluation is needed.

AMP = aging management program; GALL = Generic Aging Lessons Learned; SLR = subsequent license renewal; SRP = Standard Review Plan; TLAA = time-limited aging analysis.

The staff's evaluation of the adequacy of each generic AMP to manage certain aging effects for particular SCs is based on its review of the 10 program elements in each AMP, as defined in Table 2.

Table 2 Aging Management Programs Element Descriptions

AMP Element	Description
1. Scope of the Program	The scope of the program should include the specific structures and components subject to an aging management review.
2. Preventive Actions	Preventive actions should mitigate or prevent the applicable aging effects.
3. Parameters Monitored or Inspected	This identifies the aging effects that the program manages and provides a link between the parameter(s) that will be monitored and how the monitoring of these parameters will maintain adequate aging management.
4. Detection of Aging Effects	Detection of aging effects should occur before there is a loss of any intended function of a structure and component. This element describes aspects such as method or technique (i.e., visual, volumetric, surface inspection), frequency, sample size, data collection, and timing of new/one-time inspections to ensure timely detection of aging effects.
5. Monitoring and Trending	Monitoring and trending should provide for an estimate of the extent of the effects of aging and timely corrective or mitigative actions.
6. Acceptance Criteria	Acceptance criteria, against which the need for corrective action will be evaluated, should provide reasonable assurance that the particular structure and component's intended functions are maintained under all current licensing basis conditions during the subsequent period of extended operation.
7. Corrective Actions	Description of corrective actions that will be implemented if the acceptance criteria of the program are not met.
8. Confirmation Process	The confirmation process should provide reasonable assurance that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
9. Administrative Controls	Administrative controls should provide a formal review and approval process.
10. Operating Experience (OE)	OE applicable to the aging management program (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 managed adequately so that the intended function(s) of the structure or component will be maintained during the subsequent period of extended

AMP Element	Description
	operation. In addition, an ongoing review of both plant-specific and industry OE provides reasonable assurance that the AMP is effective in managing the aging effects for which it is credited. The AMP is enhanced or new AMPs are developed, as appropriate, when it is determined through the evaluation of OE that the effects of aging may not be adequately managed.

AMP = aging management program; OE = operating experience

Edited (E) items, in contrast to modified (M) items in the tables below, are those for which no technical aspects were changed. Examples of editorial changes include the following:

- Line item citations that were missed in SRP-SLR Table 3.X-1.
- Line item changes that only involved removing detail related to a Further Evaluation Recommended column after it was verified that the identical information was included in the SRP-SLR further evaluation section.
- Line item changes that only involved renumbering further evaluation sections.
- Aging effects changed from “and” to “or.” This could appear to be a technical change, but this is not the case because the staff confirmed that it was never the intent that both aging effects were occurring. For example, the “and” in cracking due to stress corrosion cracking and cyclic loading was replaced with “or.”
- Descriptors for the AMPs in the “Aging Management Program/ time-limited aging analyses” column were simplified if the information was provided elsewhere.
- Minor edits to component descriptions; for example: (a) deleting “elastomer” from “elastomer, elastomer seals;” (b) adding “piping” or “ducting” in front of the term “component.”

On the basis of its evaluation, if the staff determines that a program is adequate to manage certain aging effects for a particular SC without change, the “Further Evaluation” entry will indicate that no further evaluation is recommended for SLR.

Chapters X and XI of the GALL-SLR Report contain generic AMPs that the staff finds to be sufficient to manage aging effects in the subsequent period of extended operation, such as the ASME Code Section XI inservice inspection, water chemistry, or structures monitoring program.

EXPLANATION OF THE USE OF MULTIPLE AGING MANAGEMENT PROGRAMS IN AGING MANAGEMENT REVIEW ITEMS

For aging management review items associated with some "Further Evaluations," the associated "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report" (GALL-SLR Report) items now include a letter suffix with the unique chapter-specific identifier. For these items, the staff designated the various aging management programs (AMPs) it found to be acceptable in lieu of specifying "plant-specific aging management program" in the Aging Management Program column. Depending on the GALL-SLR Report Table 2 item cited in the subsequent license renewal application (SLRA) for these items, applicants can either use one of the AMPs found to be acceptable to the staff for specific situations or, comparable to any other item, can propose their own plant-specific program to manage the associated aging effect.

For example, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR)" Section 3.1.2.2.16 is a further evaluation associated with Standard Review Plan for Review of Subsequent License Renewal Item 3.1-1, 136, for loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping and piping components. The associated chapter-specific identifier has been expanded to include Items R-452a, R-452b, R-452c, and R-452d. The further evaluation recommends a review of plant-specific operating experience to determine whether the site's air environments are sufficiently aggressive to cause pitting and crevice corrosion. The need to manage this aging effect will depend on the results of the operating experience reviews and a one-time inspection to demonstrate that pitting and crevice corrosion are not occurring or are occurring sufficiently slowly. Consequently, the acceptable AMP could be XI.M32 for performing the one-time inspection (if the aging effect does not need to be periodically managed), or it could be XI.M36, XI.M38, or XI.M42, depending on whether a periodic program is needed for external surfaces, internal surfaces, or coatings/linings. The SLRA will specify the applicable AMP by citing the specific GALL-SLR Item R-452a, R-452b, R-452c, or R-452d for the corresponding AMP being used at the site. More specifically, if the plant-specific operating experience review does not reveal any instances of loss of material for stainless steel or nickel alloy piping and piping components, R-452a (AMP XI.M32) would be the cited SLRA aging management review Table 2 item. In contrast, if external loss of material has occurred, and the loss was sufficient to potentially affect the intended function, R-452b (AMP XI.M36) or R-452d (AMP XI.M42) would be cited.

REFERENCES

References are listed for each aging management program following the program elements. References consist of documents (e.g., codes, standards) associated with recommended actions (e.g., qualification of personnel, inspection methods) cited in the program elements or documents containing background information associated with the aging management program (e.g., Information Notices). The specific version (e.g., edition, addendum, revision) of a reference is cited in the list of references. Note that in some instances, specific program elements might cite a different version of a reference than that cited in the reference list. In such cases, the staff has reviewed the provisions of the different versions of the reference and has specifically cited a version based on the requirements or guidance contained in the document. Where a specific version is not cited under a program element, the version cited in the reference list is applicable. With the exception of the guidance about use of later editions/revisions of various industry documents cited below, an applicant should identify exceptions to the Generic Aging Lessons Learned for Subsequent License Renewal Report and provide justification when using a different version of a reference cited in the program elements.

GUIDANCE ON USE OF LATER EDITIONS/REVISIONS OF VARIOUS INDUSTRY DOCUMENTS

To aid applicants in the development of their subsequent license renewal applications (SLRAs), the staff has developed a list of aging management programs in the “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report” (GALL-SLR Report) that are based entirely or in part on specific editions/revisions of various industry codes (other than the American Society of Mechanical Engineers Boiler and Pressure Vessel Code), standards, and other industry-generated guidance documents. SLRAs may use later editions/revisions of these industry-generated documents, subject to the following provisions:

i. If the later edition/revision has been explicitly reviewed and approved/endorsed by the U.S. Nuclear Regulatory Commission (NRC) staff for license renewal via an NRC Regulatory Guide endorsement, a safety evaluation for generic use (such as for a Boiling Water Reactor Vessel and Internals Project (BWRVIP) report], incorporation into Title 10 of the *Code of Federal Regulation* (10 CFR), or license renewal interim staff guidance.

ii. If the later edition/revision has been explicitly reviewed and approved on a plant-specific basis by the NRC staff in its Safety Evaluation Report for another applicant’s SLRA (a precedent exists), applicants may reference it and justify its applicability to their facility via the exception process in Nuclear Energy Institute Guideline 95-10.

If either of these methods is used as justification for adopting a later edition/revision than that specified in the GALL-SLR Report, the applicant shall reference the information pertaining to the NRC endorsement/approval of the later edition/revision.

APPLICATION OF THE GENERIC AGING LESSONS LEARNED FOR SUBSEQUENT LICENSE RENEWAL (GALL-SLR) REPORT

The "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report" (GALL-SLR Report) is a technical basis document to the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants, which provides the staff with guidance when reviewing a subsequent license renewal application (SLRA). The GALL-SLR Report should be treated in the same manner as an approved topical report that is generically applicable. An applicant may reference the GALL-SLR Report in an SLRA to demonstrate that the aging management programs (AMPs) at the applicant's facility correspond to those reviewed and approved in the GALL-SLR Report.

If an applicant takes credit for an AMP in the GALL-SLR Report, it is incumbent on the applicant to ensure that the plant AMP contains all the elements of the referenced GALL-SLR program. In addition, the conditions and operating experience (OE) at the plant must be bounded by the conditions and OE for which the GALL-SLR Report AMP was evaluated; otherwise it is incumbent on the applicant to augment the GALL-SLR Report AMP as appropriate to address the impact of the plant-specific OE on the AMP element criteria. The documentation for the above verifications must be available onsite in an auditable form.

The GALL-SLR Report contains one acceptable way to manage aging effects for subsequent license renewal (SLR). An applicant may propose alternatives for staff review in its plant-specific SLRA. The use of the GALL-SLR Report is not required, but its use should facilitate both preparation of an SLRA by an applicant and timely, consistent review by the U.S. Nuclear Regulatory Commission staff.

The GALL-SLR Report does not address the scoping of structures and components for license renewal; this is addressed in Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants Chapter 2. Scoping is plant-specific, and the results depend on the plant design and current licensing basis. The inclusion of a certain structure or component in the GALL-SLR Report does not imply that the particular structure or component is within the scope of license renewal for all plants. Conversely, the omission of a certain structure or component from the GALL-SLR Report does not imply that the particular structure or component is not within the scope of SLR for any plants.

The GALL-SLR Report contains an evaluation of a large number of structures and components s that may be in the scope of a typical SLRA. The evaluation results documented in the GALL-SLR Report indicate that many existing, typical generic AMPs are adequate for managing aging effects for particular structures or components for SLR without change. The GALL-SLR Report also contains recommendations about specific areas for which existing generic AMPs should be augmented (require further evaluation) for SLR and documents the technical basis for each such determination. The GALL-SLR Report identifies certain systems, structures, and components that may or may not be subject to particular aging effects, and those for which industry is developing generic AMPs or investigating whether aging management is warranted.

Appendix A of the GALL-SLR Report addresses quality assurance (QA) for AMPs. The aspects of the aging management review process that affect the quality of safety-related SSCs are subject to the QA requirements of Appendix B to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50. For nonsafety-related SCs subject to an aging management review, the existing 10 CFR Part 50, Appendix B, QA program may be used by an applicant to address the elements of the corrective actions, confirmation process, and administrative controls for an AMP for SLR.

The GALL-SLR Report provides a technical basis for crediting existing plant AMPs and recommending areas for AMP augmentation and further evaluation. The incorporation of the GALL-SLR Report information into the SRP-SLR, as directed by the Commission, should improve the efficiency of the SLR review process and the associated use of staff resources.

CHAPTER IX

USE OF TERMS FOR STRUCTURES, COMPONENTS, MATERIALS, ENVIRONMENTS, AGING EFFECTS, AND AGING MECHANISMS

IX USE OF TERMS FOR STRUCTURES, COMPONENTS, MATERIALS, ENVIRONMENTS, AGING EFFECTS, AND AGING MECHANISMS

IX.A INTRODUCTION

This chapter is designed to clarify the use of terms in the aging management review (AMR) tables in Chapters II–VIII of this report. The format and content of the AMR tables have been retained from the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (GALL-SLR Report), to enhance the report's applicability to future subsequent license renewal applications. The U.S. Nuclear Regulatory Commission has also added several new terms and removed or clarified some of those that were in the GALL-SLR Report, Revision 0.

IX.B STRUCTURES AND COMPONENTS

This Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (GALL-SLR Report) does not address the scoping of structures and components for subsequent license renewal (SLR). Scoping is plant-specific, and the results depend on the individual plant design and its current licensing basis. The inclusion of a certain structure or component in the GALL-SLR Report does not mean that the particular structure or component is within the scope of SLR for all plants. Conversely, the omission of a certain structure or component from the GALL-SLR Report does not mean that the particular structure or component is omitted from the scope of SLR for any plant.

1 **Table IX.B. Use of Terms for Structures and Components**

Term	As Used in this Document
Bolting	Bolting can refer to structural bolting, closure bolting, or all other bolting. Within the scope of license renewal, both Class 1 and non-Class 1 systems and components contain bolted closures that are necessary for the pressure boundary of the components being joined or closed. Closure bolting in high-pressure or high-temperature systems is defined as bolting in which the pressure exceeds 275 psi or 93 °C (200 °F). Closure bolting is used to join pressure boundaries or where a mechanical seal is required.
Ducting and ducting components	Ducting and ducting components include heating, ventilation, and air conditioning (HVAC) components. Examples include ductwork, ductwork fittings, access doors, equipment frames and housing, housing supports, including housings for valves, dampers (including louvers and gravity), and ventilation fans (including exhaust fans, intake fans, and purge fans). In some cases, this includes HVAC closure bolting or HVAC piping.
Electrical insulation	Electrical insulation is a material used to inhibit/prevent the conduction of electric current. Electrical insulating materials in this category include bakelite, phenolic melamine, molded polycarbonate, organic polymers (e.g., ethylene propylene rubber, silicone rubber, ethylene propylene diene monomer, cross-linked polyethylene), and ceramics.
Encapsulation components/valve chambers	These are airtight enclosures that function as a secondary containment boundary to completely enclose containment sump lines and isolation valves. Encapsulation components and features (e.g., emergency core cooling system, containment spray system, containment isolation system, refueling water storage tank, etc.) can include encapsulation vessels, piping, and valves.
“Existing programs” components	One of four groups of pressurized water reactor vessel internal (PWR RVI) components defined in Electric Power Research Institute (EPRI) Report No. 3002017168 (Materials Reliability Program [MRP]-227, Revision 1-A) that is discussed in the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (GALL-SLR Report) Aging Management Program (AMP) XI.M16A, “PWR Vessel Internals.” Refer to Section 3.3 in the MRP-227, Revision 1-A report for EPRI’s official definition of PWR RVI “Existing Programs” components.
“Expansion” components	One of four groups of PWR RVI components defined in EPRI Report No. 3002017168 (MRP-227, Revision 1-A) that is discussed in the GALL-SLR Report AMP XI.M16A, “PWR Vessel Internals.” Refer to Section 3.3 in the MRP-227, Revision 1-A report for EPRI’s official definition of PWR RVI “Expansion” components.

Term	As Used in this Document
Eternal surfaces	In the context of structures and components (SCs), the term “external surfaces” is used to represent the external surfaces of SCs, such as tanks, that are not specifically listed elsewhere.
Heat exchanger components	A heat exchanger is a device that transfers heat from one fluid to another without the fluids coming in contact with each other. This includes air handling units and other devices that cool or heat fluids. Heat exchanger components may include, but are not limited to, air handling unit cooling and heating coils, piping/tubing, shell, plates/frames, tubesheets, tubes, valves, and bolting. Although tubes are the primary heat transfer components, heat exchanger internals, including tubesheets and fins, contribute to heat transfer and may be affected by reduction of heat transfer due to fouling [Ref. 1]. The inclusion of components such as tubesheets is dependent on manufacturer specifications.
High-voltage insulators	An insulator is an insulating material in a configuration designed to physically support a conductor and separate the conductor electrically from other conductors or objects. The high-voltage insulators that are evaluated for license renewal are those used to support and insulate high-voltage electrical components in switchyards, switching stations, and transmission lines.
Inaccessible areas of structural components for non-American Society of Mechanical Engineers (ASME) Code structural AMPs	With regard to access for routine visual examination of steel and concrete structures and components within the scope of the Structures Monitoring program and other structural AMPs not based on the ASME Code, areas considered inaccessible are those defined below: • below-grade surfaces exposed to foundation soil/material, backfill, or groundwater • portions of concrete surfaces that are covered by metallic liners • portions of surfaces where visual access is obstructed by adjacent permanent plant structures, components, equipment, parts, or appurtenances • portions of steel components, supports, connections, parts, and appurtenances that are embedded or encased in concrete or encapsulated or otherwise made inaccessible during construction or as a result of repair/replacement activities. Wetted surfaces of submerged areas or areas covered or obstructed by insulation, protective coatings, microorganisms, biofoliage or vegetation are not considered inaccessible.
Metal enclosed bus (MEB)	MEB is the term used in electrical and industry standards (Institute of Electrical and Electronics Engineers and American National Standards Institute) for electrical buses installed on electrically insulated supports constructed with all phase conductors enclosed in a metal enclosure.

Term	As Used in this Document
“No Additional Measures” components	One of four groups of (PWR RVI) components defined in EPRI Report No. 3002017168 (MRP-227, Revision 1-A) that is discussed in the GALL-SLR Report AMP XI.M16A, “PWR Vessel Internals.” Refer to Section 3.3 in the MRP-227, Revision 1-A report for EPRI’s official definition of PWR RVI “No Additional Measures” components.
Piping, piping components, and tanks	This general category includes features of the piping system within the scope of license renewal. Examples include piping, fittings, tubing, flow elements/indicators, demineralizers, nozzles, orifices, flex hoses, pump casings and bowls, safe ends, sight glasses, spray heads, strainers, thermowells, tanks and valve bodies and bonnets. For reactor coolant pressure boundary components in Chapter IV that are subject to cumulative fatigue damage, this category also can include flanges, nozzles and safe ends, penetrations, instrument connections, vessel heads, shells, welds, weld inlays and weld overlays, stub tubes, and miscellaneous Class 1 components (e.g., pressure housings, etc.).
Piping elements	The category of “piping elements” applies only to components or portions of components made of glass (e.g., the glass portion of sight glasses and level indicators). In the GALL-SLR Report, Chapters V, VII, and VIII, piping elements are thus called out separately.
Pressure housing	The term “pressure housing” only refers to pressure housing for the control rod drive head penetration (it is only of concern in Section A2 for pressurized water reactor [PWR] vessels).
“Primary” components	One of four groups of PWR RVI components defined in EPRI Report No. 3002017168 (MRP-227, Revision 1-A) that is discussed in the GALL-SLR Report AMP XI.M16A, “PWR Vessel Internals.” Refer to Section 3.3 in the MRP-227, Revision 1-A report for EPRI’s official definition of PWR RVI “Primary” components.
Reactor coolant pressure boundary components	Reactor coolant pressure boundary components include, but are not limited to, piping, piping components, flanges, nozzles, safe ends, pressurizer vessel shell heads and welds, heater sheaths and sleeves, penetrations, and thermal sleeves.
Seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	This category includes elastomer and polymer components used as sealants or gaskets.
Steel elements: liner; liner anchors; integral attachments	This category includes steel liners used in suppression pools or spent fuel pools.
Switchyard bus	Switchyard bus is the uninsulated, unenclosed, rigid electrical conductor or pipe used in switchyards and switching stations to connect two or more elements of an electrical power circuit, such as active disconnect switches and passive transmission conductors.

Term	As Used in this Document
Tanks	Tanks are large reservoirs used as hold-up volumes for liquids or gases. Tanks may have an internal liquid and/or vapor space and may be partially buried or in close proximity to soils or concrete. Tanks are treated separately from piping due to their potential need for different AMPs. One example is GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks partially buried or in contact with soil or concrete that experience general corrosion as the aging effect at the soil or concrete interface.
Thermal insulation	Thermal insulation is a material used to inhibit/prevent heat transfer across a thermal gradient. Thermal insulation materials include calcium silicate, fiberglass, Foamglas®, glass dust, cellular glass, and other materials with appropriate thermal conductivities.
Transmission conductors	Transmission conductors are uninsulated, stranded electrical cables used in switchyards, switching stations, and transmission lines to connect two or more elements of an electrical power circuit, such as active disconnect switches, power circuit breakers, and transformers and passive switchyard buses.
Vibration isolation elements	This category includes nonsteel supports used for supporting components prone to vibration.

AMP = aging management program; ASME = American Society of Mechanical Engineers; EPRI = Electric Power Research Institute; GALL-SLR = Generic Aging Lessons Learned for Subsequent License Renewal; HVAC = heating, ventilation, and air conditioning; MEB = metal enclosed bus; MRP = Materials Reliability Program; PWR = pressurized water reactor; PWR RVI = pressurized water reactor vessel internal; SCs structures and components.
(a)

IX.C MATERIALS

The following table defines many generalized materials used in the preceding Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (GALL-SLR Report) aging management review tables in Chapters II through VIII of the GALL-SLR Report.

Table IX.C. Use of Terms for Materials

Term	As Used in this Document
Aluminum	Aluminum (Al) alloy and heat treatment temper designations are used in accordance with American National Standards Institute (ANSI) document: ANSI H35.1/H35.1M.
Boraflex	Boraflex is a material composed of 46% silica, 4% polydimethylsiloxane polymer, and 50% boron carbide, by weight. It is a neutron-absorbing material used in spent fuel storage racks. Degradation of Boraflex panels under gamma radiation can lead to a loss of their ability to absorb neutrons in spent fuel storage pools. The AMP for Boraflex is found in Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMPXI.M22, “Boraflex Monitoring.”
Boral®, boron steel	Boron steel is steel with a boron content ranging from one to several percent. Boron steel absorbs neutrons and is often used as a control rod to help control the neutron flux. Boral® is a cermet consisting of a core of Al and boron carbide powder sandwiched between sheets of Al. Boral refers to patented Aluminum-Boron master alloys, which can contain up to 10% boron as AlB_{12} intermetallics.
Carbon fiber reinforced polymer (CFRP)	CFRP is a composite material that has been applied to repair the interior surfaces of degraded metallic pipe and has been credited to carry all design loads.
Cast austenitic stainless steel (CASS)	CASS alloys, such as CF-3, CF-8, CF-3M, and CF-8M, have been widely used in light water reactors. These CASS alloys are similar to wrought grades Type 304L, Type 304, Type 316L, and Type 316, except CASS typically contains 5 to 25% ferrite. CASS is susceptible to loss of fracture toughness due to thermal and neutron irradiation embrittlement.
Coatings/linings	Coatings/linings include inorganic (e.g., zinc-based, cementitious) or organic (e.g., elastomeric or polymeric) coatings, linings (e.g., rubber, cementitious), paints, and concrete surfacers designed to adhere to a component to protect its surface.
Concrete and cementitious material	When used generally, this category of concrete applies to concrete in many different configurations (block, cylindrical, etc.) and prestressed or reinforced concrete. Cementitious material can be defined as any material having cementing properties, which contributes to the formation of hydrated calcium silicate compounds. When mixing concrete, the following materials have cementitious properties: (1) Portland cement, (2) blended hydraulic cement, (3) fly ash, (4) ground granulated blast furnace slag, (5) silica fume, (6) calcined clay, (7) metakaolin, (8) calcined shale, and (9) rice husk ash. This category may include asbestos cement.
Copper alloy	This category applies to the copper alloys whose critical alloying elements are below the thresholds that make them susceptible to stress corrosion cracking (SCC), selective leaching, and boric acid corrosion. For example, copper alloys with less than 15% zinc concentration are resistant to SCC, selective leaching, and boric acid corrosion. However, these alloys are susceptible to aging effects including general, pitting, and crevice corrosion in certain environments (e.g., closed-cycle cooling water, raw water, lubricating oil, treated water). [Ref. 2, 41]

Term	As Used in this Document
Copper alloy (>15% zinc [Zn] or >8% Al)	This category applies to copper alloys whose critical alloying elements are above the thresholds that make them (in some cases) susceptible to SCC, selective leaching, and boric acid corrosion. Copper-zinc alloys >15% Zn (weight percent) are susceptible to SCC, selective leaching (dezincification), and boric acid corrosion. Copper aluminum bronze alloys >8% Al (weight percent), are susceptible to SCC or selective leaching (dealuminification), but not susceptible to loss of material due to boric acid corrosion. The percent values for zinc and aluminum are weight percent. [Ref. 2]. Inhibited brass components are resistant to dezincification as a result of the addition of alloying elements such as tin, arsenic, antimony, or phosphorous. [Ref. 35, 36].
Ductile iron	Ductile iron, similar to gray cast iron, is an iron alloy made by adding larger amounts of carbon to molten iron than would be used to make steel. Most steel has less than about 1.2% by weight carbon, while cast irons typically have between 2.5 to 4%. Ductile iron contains spherical graphite nodules, as opposed to graphite flakes for gray cast iron, resulting in increased strength and ductility when compared to gray cast iron. Ductile iron is susceptible to selective leaching, resulting in a loss of iron from the microstructure, leaving a porous matrix of graphite. In some environments, ductile iron is categorized with the group “Steel.”
Elastomers	Elastomer is an encompassing term used to refer to a variety of viscoelastic polymers including natural and synthetic rubbers. Elastomers include flexible materials such as rubber, ethylene propylene terpolymer (EPT), ethylene propylene diene monomer (EPDM), polytetrafluoroethylene elastomers (PTFEs), ethylene tetrafluoroethylene (ETFE), Viton, Vitril, neoprene, and silicone elastomer.
Galvanized steel	Galvanized steel is steel coated with Zn, usually by immersion or electrodeposition. The Zn coating protects the underlying steel because the corrosion rate of the Zn coating in dry, clean air is very low. In the presence of moisture, galvanized steel is classified under the category “Steel.”
Glass	This category includes any glass material. Glass is a hard, amorphous, brittle, super-cooled liquid made by fusing together one or more of the oxides of silicon, boron, or phosphorous with certain basic oxides (e.g., sodium, magnesium, calcium, potassium), and cooling the product rapidly to prevent crystallization or devitrification.
Graphitic tool steel	Graphitic tool steels (such as American Iron and Steel Institute [AISI] O6, which is oil-hardened, and AISI A10, which is air-hardened), have excellent nonseizing properties. The graphite particles provide self-lubricity and hold applied lubricants.
Gray cast iron	Gray cast iron is an iron alloy made by adding larger amounts of carbon to molten iron than would be used to make steel. Most steel has less than about 1.2% by weight carbon, while cast irons typically have between 2.5 to 4%. Gray cast iron contains flat graphite flakes that reduce its strength and form cracks, inducing mechanical failures. The flakes also cause the metal to behave in a nearly brittle fashion, rather than experiencing the elastic, ductile behavior of steel. Gray cast iron is susceptible to selective leaching, resulting in a loss of iron from the microstructure, leaving a porous matrix of graphite. In some environments, gray cast iron is categorized with the group “Steel.”

Term	As Used in this Document
High-strength steel	High-strength steels are those with an actual yield strength greater than or equal to 150 kilo-pounds per square inch (ksi; 1,034 megapascals [MPa]). These types of steels are susceptible to cracking. The materials are cited in GALL-SLR AMPs such as XI.M3, "Reactor Head Closure Stud Bolting," XI.M18, "Bolting Integrity," and XI.S3, "ASME Section XI, Subsection IWF." AMP XI.M3 also uses a criterion of 170 ksi (1,172 MPa) for the ultimate tensile strength of existing studs. [Ref. 40]
Lubrite®	Lubrite® refers to a patented technology in which the bearing substrate (bronze is commonly used, but in unusual environments can range from stainless steel [SS] and nodular-iron to tool-steel) is fastened to lubricant. Lubrite is often defined as bronze attached to ASTM B22, alloy 905, with G10 lubricant. Even though Lubrite bearings are characterized as maintenance-free because of the differences in their installation, fineness of the surfaces, and lubricant characteristics, they can experience mechanical wear and fretting. Bearings generally have not shown adverse conditions related to the use of Lubrite. The unique environment and precise installation tolerances required for installing the bearings require bearing-specific examinations. The vendor's (Lubrite® Technologies) literature shows 10 lubricant types used in the bearings, ranging from G1 (General Duty) to AE7 (temperature- and radiation-tested) lubricants. The type of lubricant used depends on the plant-specific requirements. Careful installation and clearing out any obstructions during installation ensures that the required tolerances of the bearings are met and reduces the likelihood of functional problems during challenging loading conditions (such as design basis accident or safe shutdown earthquake). The associated aging effects could include malfunctioning, distortion, dirt accumulation, and fatigue under vibratory and cyclic thermal loads. The potential aging effects could be managed by incorporating its periodic examination in American Society of Mechanical Engineers (ASME) Code Section XI, Subsection IWF (GALL-SLR Report AMP XI.S3) or in Structures Monitoring (GALL-SLR Report AMP XI.S6).
Malleable iron	Malleable iron, similar to gray cast iron, is an iron alloy made by adding larger amounts of carbon to molten iron than would be used to make steel. Most steel has less than about 1.2% by weight carbon, while cast irons typically have between 2.5 to 4%. Malleable iron contains irregularly shaped graphite nodules, as opposed to graphite flakes for gray cast iron, resulting in increased strength and ductility when compared to gray cast iron. Malleable iron is susceptible to selective leaching, resulting in a loss of iron from the microstructure, leaving a porous matrix of graphite. In some environments, malleable iron is categorized with the group "Steel." For high-voltage insulators, malleable iron is one of the materials in the category of "Porcelain, Malleable iron, Al, galvanized steel, cement."
Nickel alloys	Nickel alloys are nickel-chromium-iron (molybdenum) alloys and include the Alloys 600 and 690. Examples of nickel alloys include Alloy 182, 600, and 690, Gr. 688 (X-750), Inconel 182, Inconel 82, NiCrFe, SB-166, -167, and -168, and X-750. [Ref. 3]
Porcelain	Hard-quality porcelain is used as an insulator for supporting high-voltage electrical insulators. Porcelain is a hard, fine-grained ceramic that consists of kaolin, quartz, and feldspar fired at high temperatures.

Term	As Used in this Document
SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process	This category consists of quenched and tempered vacuum-treated carbon and alloy steel forgings for pressure vessels. As shown in aging management review (AMR) Item R-85, growth of intergranular separations (underclad cracks) in a low-alloy steel forging heat affected zone under austenitic SS cladding is a time-limited aging analysis (TLAA) to be evaluated for the subsequent period of extended operation for all the SA 508-Cl 2 forgings where the cladding was deposited with a high heat input welding process per ASME Code, Section XI.
Stainless steel	Products grouped under the term SS include austenitic, ferritic, martensitic, precipitation-hardened (PH), or duplex SS (Cr content >11%). These SSs may be fabricated using a wrought or cast process. These materials are susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion, and cracking due to SCC. In some cases, when an aging effect is applicable to all of the various SS categories, it can be assumed that the term “stainless steel” in the “Material” column of an AMR item in the GALL-SLR Report encompasses all SS types. CASS is quite susceptible to loss of fracture toughness due to thermal and neutron irradiation embrittlement. In addition, MRP-227, Revision 1-A indicates that PH SSs or martensitic SSs may be susceptible to loss of fracture toughness by a thermal aging mechanism. Therefore, when loss of fracture toughness due to thermal and neutron irradiation embrittlement is an applicable aging effect and mechanism for a component in the GALL-SLR Report, the CASS, PH SS, or martensitic SS designation is specifically identified in an AMR item. Steel with SS cladding also may be considered SS when the aging effect is associated with the SS surface of the material, rather than the composite volume of the material. Examples of SS designations that compose this category include A-286, SA193-Gr. B8, SA193-Gr. B8M, Gr. 660 (A-286), SA193-6, SA193-Gr. B8 or B-8M, SA453, Type 416, Type 403, 410, 420, and 431 martensitic SSs, Type 15-5, 17-4, and 13-8-Mo PH SSs, and SA-193, Grade B8 and B8M bolting materials. Examples of wrought austenitic stainless materials that compose this category include Type 304, 304NG, 304L, 308, 308L, 309, 309L, 316 and 347. Examples of CASS that compose this category include CF3, CF3M, CF8 and CF8M. [Ref. 4, 5, 6].
Steel	In some environments, carbon steel, alloy steel, gray cast iron, ductile iron, malleable iron, and high-strength low-alloy steel are vulnerable to general, pitting, and crevice corrosion, even though the rate of loss of material may vary among material types. Consequently, these metal types are generally grouped under the broad term “steel.” Note that this does not include SS, which has its own category. However, gray cast iron, ductile iron, and malleable iron are susceptible to selective leaching, and high-strength low-alloy steel is susceptible to SCC. Therefore, when these aging effects are being considered, these materials are specifically identified. Galvanized steel (Zn-coated carbon steel) is also included in the category of “steel” when exposed to moisture. Malleable iron is also specifically called out in the phrase “Porcelain, Malleable iron, Al, galvanized steel, cement,” which is used to define the high-voltage insulators in GALL-SLR Chapter VI.

Term	As Used in this Document
	Examples of steel designations included in this category are ASTM A36, ASTM A285, ASTM A759, SA36, SA106-Gr. B, SA155-Gr. KCF70, SA193-Gr. B7, SA194 -Gr. 7, SA302-Gr B, SA320-Gr. L43 (AISI 4340), SA333-Gr. 6, SA336, SA508-64, class 2, SA508-Cl 2 or Cl 3, SA516-Gr. 70, SA533-Gr. B, SA540-Gr. B23/24, and SA582. [Ref. 4, 5]
Stellite	ASTM International provides a technical definition of Stellite in ASTM MNL46, “Metallographic and Materialographic Specimen Preparation, Light Microscopy, Image Analysis and Hardness Testing”: “Stellite is a special cobalt-based alloy with 46–65 % Co, 25–25 % Cr, and 5–20 % W. The material is very wear resistant…”
Superaustenitic stainless steel	Superaustenitic SSs have the same structure as the common austenitic alloys, but they have enhanced levels of elements such as chromium, nickel, molybdenum, copper, and nitrogen, which give them superior strength and corrosion resistance. Compared to conventional austenitic SSs, superaustenitic materials have a superior resistance to pitting and crevice corrosion in environments containing halides. Several nuclear power plants have installed superaustenitic SS (AL-6XN) buried piping.
Titanium	The category titanium includes unalloyed titanium (ASTM grades 1-4) and various related alloys (ASTM grades 5, 7, 9, 11, and 12). The corrosion resistance of titanium is a result of the formation of a continuous, stable, highly adherent protective oxide layer on the metal surface. The AMR tables in some instances, depending on the specific grade of titanium, state that there are no aging effects requiring management. However, titanium in general is susceptible to reduction of heat transfer due to fouling or flow blockage due to fouling depending upon the specific environment (e.g., E-458). Titanium and titanium alloys may be susceptible to crevice corrosion in saltwater environments at elevated temperatures >71 °C (>160 °F). Titanium Grades 5 and 12 are resistant to crevice corrosion in seawater at temperatures as high as 500 °F. SCC of titanium and its alloys is considered applicable in seawater or brackish raw water systems if the titanium alloy contains more than 6% Al or more than 0.30% oxygen or any amount of tin [Ref. 7]. ASTM Grades 1, 2, 7, 9, 11, or 12 are not susceptible to SCC in seawater or brackish raw water [Ref. 8].
Various organic polymers	Polymers used in electrical applications include ethylene-propylene copolymer EPR, SR, EPDM, and XLPE. XLPE is a cross-linked polyethylene thermoplastic resin, such as polyethylene and polyethylene copolymers. EPR and EPDM are EPRs in the category of thermosetting elastomers.

Term	As Used in this Document
Various polymeric materials	Polymers used in mechanical applications are either addressed as specific material types (e.g., polyvinyl chloride (PVC), high-density polyethylene (HDPE), carbon fiber reinforced polymer, fiberglass); or generically as elastomers used in different components types (e.g., piping, seals, linings, fire barriers) with distinct aging effects, or broadly as polymerics where a wide range of potential aging effects are cited. Unless otherwise justified in the SLR application (or as follows), when the material type is cited as “polymeric,” inspections are conducted in a manner conducive to detecting all cited aging effects. Flow blockage due to fouling need not be considered for polymeric materials exposed to air (external), condensation (external), underground environment, and concrete environments. For the concrete environment, inspections consistent with GALL-SLR Report AMP XI.M41 are acceptable. Hardening need not be detected in rigid polymers.
Wood	Wood piles or sheeting exposed to flowing or standing water is subject to loss of material or changes in material properties due to weathering, chemical degradation, insect infestation, repeated wetting and drying, or fungal decay. Wooden poles exposed to air-outdoor, groundwater and/or soil are subject to loss of material and/or changes in material properties due to weathering, chemical degradation, insect infestation, repeated wetting and drying, or fungal decay.
Zircaloy-4 (Zry-4)	Zry-4 is a member in the group of high-zirconium (Zr) alloys. Such Zircaloys are used in nuclear technology because Zr has very low absorption cross section of thermal neutrons. In the GALL-SLR Report, Zry-4 is referenced in AMR Item IV.B3.RP-357 for incore instrumentation thimble tubes. Zry-4 consists of 98.23 weight % Zr with 1.45% tin, 0.21% iron, 0.1% chromium, and 0.01% hafnium.

AISI = American Iron and Steel Institute; AMP = aging management program; AMR = aging management review; ANSI = American National Standards Institute; ASME = American Society of Mechanical Engineers; CASS = cast austenitic stainless steel’ CFRP = carbon fiber-reinforced polymer; EPDM = ethylene propylene diene monomer; EPR = ethylene-propylene copolymer; EPT = ethylene propylene terpolymer (EPT); GALL-SLR = Generic Aging Lessons Learned for Subsequent License Renewal; PH = precipitation-hardened; SCC = stress corrosion cracking; SS = stainless steel; TLAA = time-limited aging analysis; XLPE = cross-linked polyethylene.

IX.D ENVIRONMENTS

The following table defines many of the standardized terms for environments used in the preceding Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (GALL-SLR Report) aging management review (AMR) tables in Chapters II through VIII of the GALL-SLR Report. The use of temperature thresholds for describing aging effects is continued as in the “Generic Aging Lessons Learned (GALL) Report,” Revision 2 (GALL Report, Revision 2).

Environmental stressors for elastomeric and polymeric materials – In general, if the ambient temperature is less than about 35 °C (Celsius; 95 °F [Fahrenheit]), then thermal aging may be considered not significant for rubber, butyl rubber, neoprene, nitrile rubber, silicone elastomer, fluoroelastomer, ethylene-propylene rubber, and ethylene propylene diene monomer [Ref. 9]. Hardening or the loss of strength in elastomers and polymers can be induced by thermal aging, exposure to ozone, oxidation, photolysis (due to ultraviolet light), and radiation. When applied to the elastomers used in electrical cable insulation, note that most cable insulation is manufactured as either 75 °C (167 °F) or 90 °C (194 °F) rated material.

Temperature threshold of 60 °C (140 °F) for stress corrosion cracking (SCC) in stainless steel (SS) – SCC occurs very rarely in austenitic SSs below 60 °C (140 °F). Although SCC has been observed in stagnant, oxygenated borated water systems at lower temperatures than this 60 °C [140 °F] threshold, all of such instances have identified a significant presence of contaminants (halogens, specifically chlorides) in the failed components. In a harsh enough environment (e.g., significant contamination), SCC can occur in austenitic SS at ambient temperature. In a water environment in which the concentration of contaminants (e.g., sulfates, chlorides, fluorides) is maintained consistent using a water chemistry program, these conditions are considered event-driven, resulting from a breakdown of chemistry controls. However, in environments in which the chemistry is not controlled (e.g., air-outdoor, soil, exposure to leakage from bolted connections in the vicinity of the component), SCC can occur at ambient temperature. In air-outdoor environments, surface temperatures exposed directly to sunlight will be higher than ambient air conditions [Ref. 8, 10, 11].

Temperature threshold of 250 °C [482 °F] for thermal embrittlement in cast austenitic stainless steel (CASS) – CASS subjected to sustained temperatures below 250 °C (482 °F) will not result in a reduction of room temperature Charpy impact energy below 50 foot-pounds (ft-lb) for exposure times of approximately 300,000 hours (for CASS with a ferrite content of 40 percent, and approximately 2,500,000 hours for CASS with a ferrite content of 14 percent) [Fig. 2; Ref. 12]. For a maximum exposure time of approximately 420,000 hours (48 effective full power years [EFPYs]), a screening temperature of 250 °C (482 °F) is conservatively chosen because (1) most nuclear-grade materials is expected to contain a ferrite content well below 40 percent, and (2) the 50 ft-lb limit is very conservative when applied to cast austenitic materials. It is typically applied to ferritic materials (e.g., Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50 (TN249) Appendix G). For CASS components in the reactor coolant pressure boundary, this threshold is supported by the GALL-SLR Report AMP XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS),” with the exception of niobium-containing steels, which require evaluation on a case-by-case basis.

Table IX.D. Use of Terms for Environments

Term	As Used in this Document
Adverse localized environment	An adverse localized environment is an environment limited to the immediate vicinity of a component that is hostile to the component material, thereby leading to potential aging effects. Electrical insulation used for electrical cables can be subjected to an adverse localized environment. Adverse localized environment can be due to any of the following: (1) exposure to significant moisture, or (2) heat, radiation, or moisture and is represented by specific GALL-SLR AMR items.
Aggressive environment (steel in concrete)	This environment affects steel embedded in concrete with a pH <5.5 or a chloride concentration >500 ppm or sulfate >1,500 ppm. [Ref. 13]
Air	Any indoor or outdoor air environment in which the cited aging effects could occur regardless of the particular air environment (e.g., air-indoor uncontrolled, air-outdoor). For example: (1) hardening or loss of strength of elastomeric components occurs in many different air environments depending upon environmental parameters such as temperature, ozone, ultraviolet light, and radiation; and (2) loss of preload for closure bolting can occur in a variety of air environments. The term “air” was incorporated to allow the aging management review line items to be more succinct with regard to citing environments. This term does not encompass the air environment downstream of instrument air dryers, air-dry (defined below), or the underground environment. The potential for leakage from bolted connections (e.g., flanges, packing) affecting in-scope components exists when citing the air environment.
Air–dry	Air that has been treated to reduce its dew point well below the system operating temperature and treated to control lubricant content, particulate matter, and other corrosive contaminants. Use of this term is only associated with internal air environments located downstream of the compressed air system air dryers. The associated aging management review items cite loss of material as an aging effect and GALL-SLR Report aging management program (AMP) XI.M24, “Compressed Air Monitoring,” as the recommended AMP. AMP XI.M24 recommends opportunistic inspections for loss of material and, therefore, the line items were revised to cite the loss of material.
Air–indoor controlled	An environment in which the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment. For electrical components and structures, the environment control must be sufficient to show that the electrical component(s) or structure(s) are not subjected to the cited aging effect(s) (e.g., reduced insulation resistance). The potential for leakage from bolted connections (e.g., flanges, packing) affecting in-scope components should be considered when citing the air–indoor controlled environment.

Term	As Used in this Document
Air–indoor uncontrolled	Air–indoor uncontrolled is associated with systems with temperatures higher than the dew point (i.e., condensation can occur, but only rarely; equipment surfaces are normally dry). The potential for leakage from bolted connections (e.g., flanges, packing) affecting in-scope components should be considered when citing the air–indoor uncontrolled environment.
Air–outdoor	The outdoor environment consists of moist, possibly salt-laden air and spray, cooling tower plumes (which might contain chemical additives), industrial pollutants (e.g., fly ash, soot), ambient temperatures and humidity, and exposure to weather events, including precipitation and wind. The outdoor air environment also potentially includes component contamination due to animal infestation including by-products or excrement-containing uric acid, ammonia, phosphates, or other compounds. The outdoor air environment can also result in submergence of components (particularly when they are in vaults) due to the potential for water to accumulate or due to external or internal buildup of condensation.
Air with borated water leakage	Air and untreated borated water leakage on indoor or outdoor systems with temperatures either above or below the dew point. The water from leakage is considered to be untreated, due to the potential for water contamination at the surface (germane to pressurized water reactors [PWRs]).
Any	With some exceptions, this could be any environment in which the cited aging effects could occur regardless of the particular environment (e.g., air, water, lubricating oil). For example, loss of preload is an applicable aging effect for bolting in air as well as fluid environments. This term includes all fluid and air environments (with the exception of air-dry [internal], but excludes underground). For structural components (i.e., GALL-SLR Chapters II and III) the term “any” includes groundwater and soil environments. For mechanical components (i.e., GALL-SLR Chapters IV, V, VII, and VIII) the term “any” excludes underground, soil, and concrete environments where water could be present (i.e., the environments addressed in GALL-SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks”).
Buried	Buried piping and tanks are those in direct contact with soil, or those in contact with concrete where water could be present (e.g., a wall penetration). When the soil environment is cited, the term includes exposure to groundwater.
Closed-cycle cooling water	A subset of treated water that is subject to the closed treated water systems program. Systems are closed in that the rate of recirculation is much higher than the rate of makeup water addition. Examples include the closed portions of heating, ventilation, and air conditioning (HVAC) systems and diesel generator cooling water systems. Closed-cycle cooling water systems above 60 °C (>140 °F) exceed the threshold for stainless steel (SS) stress corrosion cracking (SCC).
Concrete	This environment consists of components that sit on concrete or are embedded in concrete.

Term	As Used in this Document
Condensation	Condensation on the surfaces of systems at temperatures below the dew point facilitates loss of material in steel caused by general, pitting, and crevice corrosion. It also facilitates cracking in materials susceptible to SCC due to the potential for internal or external surface contamination. The former term “moist air” is subsumed by the term “condensation.” Moisture in the air can result in loss of material or cracking due to hygroscopic surface contaminants. Condensation can form between thermal insulation and a component when air intrusion occurs through minor gaps in the insulation and when the operating temperature of the component is below the dew point of the penetrating air.
Containment environment (inert)	A drywell environment is made inert with nitrogen to render the primary containment atmosphere nonflammable by maintaining the oxygen content below 4% by volume during normal operation.
Diesel exhaust	This environment consists of gases, fluids, and particulates present in diesel engine exhaust.
Fuel oil	Diesel oil, No. 2 oil, or other liquid hydrocarbons used to fuel diesel engines. Fuel oil used for combustion engines may be contaminated with water, which may promote additional aging effects.
Gas	Internal gas environments include inert or nonreactive gases. This generic term is used only with “Common Miscellaneous Material/Environment,” where aging effects are not expected to degrade the ability of the structure or component to perform its intended function for the subsequent period of extended operation. The term “gas” is not meant to comprehensively include all gases in the fire suppression system. The GALL-SLR Report AMP XI.M26, “Fire Protection,” is used for the periodic inspection and testing of the halon/carbon dioxide fire suppression system.
Groundwater/soil	Groundwater is subsurface water that can be detected in wells, tunnels, or drainage galleries, or that flows naturally to the Earth’s surface via seeps or springs. Soil is a mixture of organic and inorganic materials produced by the weathering of rock and clay minerals or the decomposition of vegetation. Voids containing air and moisture can occupy 30–60% of the soil volume [Ref.14]. Concrete subjected to a groundwater/soil environment can be vulnerable to an increase in porosity and permeability, cracking, loss of material (spalling, scaling), or aggressive chemical attack. Other materials with prolonged exposures to groundwater or moist soils are subject to the same aging effects as the systems and components exposed to raw water.

Term	As Used in this Document
Lubricating oil	Lubricating oils are low-to-medium viscosity hydrocarbons that can contain contaminants and/or moisture. This term also functionally encompasses hydraulic oil (nonwater based). These oils are used for bearing, gear, and engine lubrication. The GALL-SLR Report AMP XI.M39, “Lubricating Oil Analysis,” addresses this environment. Piping and piping components, whether copper, SS, or steel, when exposed to lubricating oil with some water, will have limited susceptibility to aging degradation due to general or localized corrosion. Lubricating oil (waste oil) and lubricating oil are two different environments. Lubricating oil (waste oil) is oil that has been collected as it leaks from a component (e.g., reactor coolant pumps) and as such, contains potential contaminants such as water and dirt. Lubricating oil is unlikely to contain contaminants due to the testing of the oil and the corrective actions taken when contaminants are detected. As a result, one-time inspections for components exposed to these environments are treated as two separate populations.
Raw water	Raw water consists of untreated surface or groundwater, whether fresh, brackish, or saline in nature. This includes water for use in open-cycle cooling water systems and may include potable water—water that is used for drinking or other personal use. See also *condensation*.
Reactor coolant	Reactor coolant is treated water in the reactor coolant system and connected systems at or near full operating temperature, including steam associated with boiling water reactors (BWRs).
Reactor coolant >250 °C (>482°F)	Treated water above the thermal embrittlement threshold for cast austenitic stainless steel (CASS).
Reactor coolant >250 °C (>482°F) and neutron flux	Treated water in the reactor coolant system and connected systems above the thermal embrittlement threshold for CASS.
Reactor coolant and high fluence (>1 × 10^{21} n/cm^2 E >0.1 MeV)	Reactor coolant subjected to a high fluence (>1 × 10^{21} n/cm^2 E >0.1 MeV).
Reactor coolant and neutron flux	The reactor core environment that will result in a neutron fluence exceeding 10^{17} n/cm^2 (E >1 MeV) at the end of the license renewal term.
Reactor coolant and secondary feedwater/steam	Water in the reactor coolant system and connected systems at or near full operating temperature and the PWR feedwater or steam at or near full operating temperature, subject to the secondary water chemistry program (GALL-SLR Report AMP XI.M2).
Secondary feedwater	Within the context of the recirculating steam generator, components such as steam generator feedwater impingement plate and support may be subjected to loss of material due to erosion in a secondary feedwater environment. More generally, the environment of concern is a secondary feedwater/steam combination.
Secondary feedwater/steam	PWR feedwater or steam at or near full operating temperature, subject to the secondary water chemistry program (GALL-SLR Report AMP XI.M2).
Sodium pentaborate solution	Treated water that contains a mixture of borax and boric acid.

Term	As Used in this Document
Soil	Soil is a mixture of inorganic materials produced by the weathering of rock and clay minerals, and organic material produced by the decomposition of vegetation. Voids containing air and moisture occupy 30–60% of the soil volume [Ref. 14]. Properties of soil that can affect degradation kinetics include moisture content, pH, ion exchange capacity, density, and hydraulic conductivity. External environments included in the soil category consist of components at the air/soil interface, buried in the soil, or exposed to groundwater in the soil. See also *groundwater/soil*.
Steam	The steam environment is managed by the BWR water chemistry program or PWR secondary plant water chemistry program. Defining the temperature of the steam is not considered necessary for analysis.
System temperature up to 288 °C (550 °F)	This environment consists of a metal temperature of BWR components <288 °C (550 °F).
System temperature up to 340 °C (644 °F)	This environment consists of a maximum metal temperature <340 °C (644 °F).
Treated borated water	Borated (PWR) water is a controlled water system. The chemical and volume control system maintains the proper water chemistry in the reactor coolant system, while adjusting the boron concentration during operation to match long-term reactivity changes in the core.
Treated borated water >250 °C (>482 °F)	Treated water with boric acid above the 250 °C (>482 °F) thermal embrittlement threshold for CASS.
Treated borated water >60 °C (>140 °F)	Treated water with boric acid in PWR systems above the 60 °C (>140 °F) SCC threshold for SS.
Treated water	Treated water is water whose chemistry has been altered and is maintained (as evidenced by testing) in a state that differs from naturally occurring sources so as to meet a desired set of chemical specifications. Treated water generally falls into one of two categories. (1) The first category is based on demineralized water and, with the possible exception of boric acid (for PWRs only), generally contains minimal amounts of any additions. This water is generally characterized by high purity, low conductivity, and very low oxygen content. This category of treated water is generally used as BWR coolant and PWR primary and secondary water. (2) The second category may be, but need not be, based on demineralized water. It contains corrosion inhibitors and also may contain biocides or other additives. This water will generally be comparatively higher in conductivity and oxygen content than the first category of treated water. This category of treated water is generally used in HVAC systems, auxiliary boilers, and diesel engine cooling systems. Closed-cycle cooling water (CCCW) is a subset of this category of treated water.
Treated water >60 °C (>140 °F)	Treated water above the 60 °C (140 °F) SCC threshold for SS.

Term	As Used in this Document
Underground	Underground piping and tanks are below grade, but are contained within a tunnel or vault such that they are in contact with air and are located where access for inspection is limited (e.g., special lifting equipment is required to gain access to the vault). When the underground environment is cited, the term includes exposure to air-outdoor, air-indoor uncontrolled, air, raw water, groundwater, and condensation.
Waste water	Radioactive, potentially radioactive or nonradioactive waters that are collected from equipment and floor drains. Waste waters may contain contaminants, including oil and boric acid, depending on location, as well as originally treated water that is not monitored by a chemistry program.
Water-flowing	Water that is refreshed; thus, it has a greater impact on leaching and can include rainwater, raw water, groundwater, or water flowing under a foundation.
Water-standing	Water that is stagnant and unrefreshed, thus possibly resulting in increased ionic strength up to saturation.

IX.E AGING EFFECTS

The following table explains the selected use of many of the standardized aging effects due to associated aging mechanisms used in the preceding Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (GALL-SLR Report) aging management review tables in Chapters II through VIII of the GALL-SLR Report.

1 **Table IX.E. Use of Terms for Aging Effects**

Term	As Used in this Document
Changes in dimensions	Changes in dimension can result from various phenomena, such as void swelling, and on a macroscopic level, denting.
Concrete cracking and spalling	Cracking and exfoliation of concrete as the result of freeze-thaw, aggressive chemical attack, and reaction with aggregates.
Corrosion of connector contact surfaces	Corrosion of exposed connector contact surfaces when caused by borated water intrusion.
Crack growth	Increase in crack size attributable to static or cyclic loading.
Cracking	Fracture of a structural material. In metals, this term is synonymous with the phrase, "crack initiation and growth." In concrete, cracking may be caused by restraint shrinkage, creep, settlement, and aggressive environments. In polymeric materials, cracking (and blistering) may be caused by exposure to ultraviolet light, ozone, radiation, temperature, or moisture. In carbon fiber reinforced polymer (CFRP)-repaired pipe, cracking may occur by delamination or debonding (or disbonding), i.e., separation of CFRP layers, between fibers and matrix, or between CFRP laminate and pipe substrate.
Cracks; distortion; increase in component stress level	Within concrete structures, cracks, distortion, and increase in component stress level when caused by settlement. Although settlement can occur in a soil environment, the symptoms can be manifested in any environment.
Cumulative fatigue damage	Cumulative fatigue damage is due to fatigue, as defined by the applicable ASME Code.
Denting	Denting in steam generators can result from corrosion of carbon steel tube support plates.
Expansion and cracking	Within concrete structures, expansion and cracking can result from reaction with aggregates.
Fatigue	Fatigue in metallic fuse holder clamps can result from ohmic heating, thermal cycling, electrical transients, frequent manipulation, and vibration. [Ref. 15]
Flow blockage	Flow blockage is the reduction of flow and/or pressure in a component due to fouling, which can occur because of accumulations of particulate fouling, biofouling, or macro fouling (including delamination/disbonding of CFRP-repaired piping) . In addition to affecting the “pressure boundary” intended function (as it relates to sufficient flow at adequate pressure), flow blockage can also affect the “heat transfer,” “spray,” and “throttle” intended functions.
Hardening or loss of strength	Hardening (loss of flexibility) and loss of strength (loss of ability to withstand tensile or compressive stress) can result from elastomer or polymer degradation of seals and other components. Degraded elastomers or polymers can experience increased hardness, shrinkage, loss of sealing, cracking, and loss of strength. Hardening or loss of strength of elastomers or polymers can be induced by elevated temperature (over about 35 °C [95 °F]), and additional aging factors (e.g., exposure to ozone, oxidation, photolysis [due to ultraviolet light], and radiation). [Ref. 9]

Term	As Used in this Document
Increase in porosity and permeability, cracking, loss of material (spalling, scaling), loss of strength	Porosity and permeability, cracking, and loss of material (spalling, scaling) in concrete can increase due to aggressive chemical attack. In concrete, the loss of material (spalling, scaling) and cracking can result from the freeze-thaw processes. Loss of strength can result from leaching of calcium hydroxide in the concrete.
Increased resistance of connection	Increased resistance of connection is an aging effect that can be caused by the loosening of bolts resulting from thermal cycling and ohmic heating. [Ref. 17, 18] In the GALL-SLR Report Chapter VI aging management review (AMR) items, increased resistance to connection is also said to be caused by the following aging mechanisms: • 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) • Thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation • Fatigue caused by frequent manipulation or vibration • Corrosion of connector contact surfaces caused by intrusion of borated water • Oxidation or loss of preload.
Ligament cracking	Steel tube support plates can experience ligament cracking due to corrosion. As previously noted in IN 96-09, tube support plate signal anomalies found during eddy current testing of steam generator tubes may be indicative of support plate damage or ligament cracking.
Long-term loss of material	The term “long-term loss of material” was incorporated into the GALL-SLR Report to differentiate it from the term “loss of material.” Original plant designs should have included at least a 40-year corrosion allowance for steel systems. For steel systems exposed to water environments without corrosion inhibitors, it is appropriate to confirm that the rate of loss of material will not challenge the structural integrity of these systems throughout an 80-year span of operation. Long-term loss of material is addressed once prior to entering the subsequent period of extended operation, as long as the results of volumetric examinations establish that the structural integrity intended function(s) of the in-scope components will be met until the end of 80 years of operation. In contrast, loss of material is addressed in periodic or opportunistic inspections conducted throughout the subsequent period of extended operation.

Term	As Used in this Document
Loss of coating or lining integrity	Loss of coating or lining integrity is the disbondment of a coating/lining from its substrate. Loss of coating or lining integrity can be due to a variety of aging mechanisms such as blistering, cracking, flaking, peeling, delamination, rusting, or physical damage, and spalling for cementitious coatings/linings. Where the aging mechanism results in exposure of the base material, loss of base material can occur. Where the aging mechanism results in the coating/lining not remaining adhered to the substrate, the coating/lining can become debris that could prevent an in-scope component from satisfactorily accomplishing any of its functions identified under Title 10 of the *Code of Federal Regulations* (10 CFR) 54.4(a)(1)(TN4878) or (a)(3) (e.g., reduction in flow, drop in pressure, reduction of heat transfer).
Loss of conductor strength	Transmission conductors can experience loss of conductor strength due to corrosion.
Loss of fracture toughness	Loss of fracture toughness can result from various aging mechanisms, including thermal aging embrittlement and neutron irradiation embrittlement.
Loss of leak tightness	Steel airlocks can experience loss of leak tightness in the closed position resulting from mechanical wear of locks, hinges, and closure mechanisms.
Loss of material	Loss of material in mechanical components may be due to general corrosion, boric acid corrosion, pitting corrosion, galvanic corrosion, crevice corrosion, erosion, fretting, flow-accelerated corrosion, microbiologically influenced corrosion, fouling, selective leaching, wastage, and wear. In concrete structures, loss of material can also be caused by aggressive chemical attack, abrasion, cavitation, or corrosion of embedded steel. In polymeric materials, loss of material can be caused by wear, environmental exposure (e.g., chemical attack, moisture), and, for CFRP pipe repairs, delamination and disbonding between the CFRP layers and between the CFRP and pipe substrate. For high-voltage insulators, loss of material can be attributed to mechanical wear or wind-induced abrasion.
Loss of material, loss of form	In earthen water-control structures, the loss of material and loss of form can result from erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage.

Term	As Used in this Document
Loss of mechanical function	Loss of mechanical function in Class 1 piping and components (such as constant and variable load spring hangers, guides, stops, sliding surfaces, and vibration isolators) fabricated from steel or other materials, such as Lubrite®, can occur through the combined influence of a number of aging mechanisms. Such aging mechanisms can include corrosion, distortion, dirt accumulation, overload, fatigue due to vibratory and cyclic thermal loads, or elastomer or polymer hardening. Clearances being less than the design requirements can also contribute to loss of mechanical function.
Loss of preload	Loss of preload can be due to gasket creep, thermal or irradiation effects (including differential expansion and creep or stress relaxation), and self-loosening (which includes vibration, joint flexing, cyclic shear loads, thermal cycles). [Ref. 19]
Loss of prestress	Loss of prestress in structural steel anchorage components can result from relaxation, shrinkage, creep, or elevated temperatures.
Loss of sealing; leakage through containment	Loss of sealing and leakage through containment in materials such as seals, elastomers, rubber, and other similar materials can result from deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants). Loss of sealing in elastomeric phase bus enclosure assemblies can result from moisture intrusion.
None	Certain material/environment combinations may not be subject to significant aging mechanisms; thus, there are no relevant aging effects that require management.
Reduced electrical insulation resistance	Reduced electrical insulation resistance is the decrease in the effectiveness of the electrical insulation to inhibit/prevent the conduction of an electric current. Reduced electrical insulation resistance is an aging effect associated with the following aging mechanisms: • Thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, and ohmic heating • Presence of salt deposits or surface contamination • Thermal/thermoxidative degradation of organics, radiolysis, and photolysis (ultraviolet-sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion moisture • Moisture
Reduced thermal insulation resistance	Reduced thermal insulation resistance is a decrease in the effectiveness of the thermal insulation to inhibit/prevent heat transfer across a thermal gradient. Reduced thermal insulation resistance can be the result of moisture intrusion and/or the exposure to moisture.
Reduction in concrete anchor capacity due to local concrete degradation	Reduction in concrete anchor capacity due to local concrete degradation can result from a service-induced cracking or other concrete aging mechanisms.

Term	As Used in this Document
Reduction in foundation strength, cracking, differential settlement	Reduction in foundation strength, cracking, and differential settlement can result from the erosion of porous concrete subfoundation.
Reduction in impact strength	Exposure of polyvinyl chloride piping and piping components to sunlight for 2 years or longer can result in a reduction in impact strength. Other polymeric materials are subject to embrittlement due to environmental conditions such as sunlight, ozone, chemical vapors, or loss of plasticizers due to evaporation. [Ref. 16]
Reduction of heat transfer	Reduction of heat transfer can result from fouling on the heat transfer surface. Although in heat exchangers the tubes are the primary heat transfer component, heat exchanger internals, including tubesheets and fins, contribute to heat transfer and may be affected by the reduction of heat transfer due to fouling. Although the GALL-SLR Report does not include reduction of heat transfer for any heat exchanger surfaces other than tubes, reduction of heat transfer is of concern for other heat exchanger surfaces.
Reduction of neutron-absorbing capacity	Reduction of neutron-absorbing capacity can result from Boraflex degradation.
Reduction of strength and modulus	In concrete, reduction of strength and modulus can be attributed to elevated temperatures (>66 °C [>150 °F] general; >93 °C [>200 °F] local).
Reduction or loss of isolation function	Reduction or loss of isolation function in polymeric vibration isolation elements can result from elastomers being exposed to radiation hardening, temperature, humidity, sustained vibratory loading.
Wall thinning	Wall thinning is a specific type of loss of material attributed in the AMR items to general corrosion, flow-accelerated corrosion, and erosion mechanisms including cavitation, flashing, droplet impingement, or solid particle impingement.

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IX.F SIGNIFICANT AGING MECHANISMS

An aging mechanism is considered to be significant when it may result in aging effects that produce a loss of functionality of a component or structure during the current license period or license renewal period if allowed to continue without mitigation.

The following table defines many of the standardized aging mechanisms used in the preceding Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management review line item tables in Chapters II through VIII of GALL-SLR Report.

Table IX.F. Use of Terms for Aging Mechanisms

Term	As Used in this Document
Abrasion	As used in the context of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report, Chapter III, “Structures and Component Supports,” as water migrates over a concrete surface, it may transport material that can abrade the concrete. The passage of water also may create a negative pressure at the water/air-to-concrete interface that can result in abrasion and cavitation degradation of the concrete. This may result in pitting or aggregate exposure due to loss of cement paste. [Ref. 20]
Aggressive chemical attack	Concrete, being highly alkaline (pH >12.5), is degraded by strong acids. Chlorides and sulfates of potassium, sodium, and magnesium may attack concrete, depending on their concentrations in soil/groundwater that come into contact with the concrete. Exposed surfaces of Class 1 structures may be subject to sulfur-based acid-rain degradation. The minimum thresholds causing concrete degradation are 500 ppm chlorides and 1,500 ppm sulfates. [Ref. 20]
Boraflex degradation	Boraflex degradation may involve gamma radiation-induced shrinkage of Boraflex and the potential to develop tears or gaps in the material. A more significant potential degradation is the gradual release of silica and the depletion of boron carbide from Boraflex, following gamma irradiation and long-term exposure to the wet pool environment. The loss of boron carbide from Boraflex is characterized by slow dissolution of the Boraflex matrix from the surface of the Boraflex and a gradual thinning of the material. The boron carbide loss can result in a significant increase in the reactivity within the storage racks. An additional consideration is the potential for silica transfer through the fuel transfer canal into the reactor core during refueling operations and its effect on the fuel-clad heat transfer capability. [Ref. 21]
Boric acid corrosion	Corrosion by boric acid, which can occur where there is borated water leakage in an environment described as air with borated water leakage (see *corrosion*).
Cavitation	Formation and instantaneous collapse of innumerable tiny voids or cavities within a liquid subjected to rapid and intense pressure changes. Cavitation caused by severe turbulent flow can potentially lead to cavitation damage.
Chemical contamination	Presence of chemicals that do not occur under normal conditions at concentrations that could result in the degradation of the component.
Cladding degradation	This refers to the degradation of the stainless steel (SS) cladding via any applicable degradation process and is a precursor to cladding breach. It is only used to describe the loss of material due to pitting and crevice corrosion (only for steel after cladding degradation) of piping, piping components, and fabricated from steel, with SS cladding.

Term	As Used in this Document
Corrosion	Chemical or electrochemical reaction between a material, usually a metal, and the environment or between two dissimilar metals that produces a deterioration of the material and its properties.
Corrosion of carbon steel tube support plate	Corrosion can occur on the carbon steel tube support plates, which are plate-type components providing tube-to-tube mechanical support for the tubes in the tube bundle of the steam generator (recirculating) system of a pressurized water reactor (PWR). The tubes pass through drilled holes in the plate. The secondary coolant flows through the tube supports via flow holes between the tubes. [Ref. 22, 23]
Corrosion of embedded steel	If the pH of concrete in which steel is embedded is reduced below 11.5 by intrusion of aggressive ions (e.g., chlorides > 500 ppm) in the presence of oxygen, embedded steel may corrode. A reduction in pH may be caused by the leaching of alkaline products through cracks, entry of acidic materials, or carbonation. Chlorides may be present in the constituents of the original concrete mix. The severity of the corrosion is affected by the properties and types of cement, aggregates, and moisture content. [Ref. 24]
Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation	This term applies to concrete, concrete cylinder pipe, reinforced concrete, asbestos cement, and cementitious components in GALL-SLR Report Chapter VII. Aging mechanisms associated with cracking are described in American Concrete Institute (ACI) 224.1R-07, “Causes, Evaluation, and Repair of Cracks in Concrete Structures.” For example, chemical reaction includes (1) reaction with aggregates, (2) effects of sulfates in the soil, and (3) effects of deicing salts. The increased porosity and permeability of cementitious materials can also result in cracking. Aging mechanisms associated with loss of material are described in ACI 201.1R-08, “Guide for Conducting a Visual Inspection of Concrete in Service.” [Ref. 37, 38]
Creep	Creep, for a metallic material, refers to a time-dependent continuous deformation process under constant stress. It is an elevated temperature process and is not a concern for low-alloy steel below 371 °C (700 °F), for austenitic alloys below 538 °C (1,000 °F), or for Ni-based alloys below 982 °C (1,800 °F). [Ref. 25, 26] Creep, in concrete, is related to the loss of absorbed water from the hydrated cement paste. It is a function of the modulus of elasticity of the aggregate. It may result in loss of prestress in the tendons used in prestressed concrete containment. [Ref. 22]

Term	As Used in this Document
Crevice corrosion	Crevice corrosion is localized corrosion of metal surface at, or immediately adjacent to, an area that is shielded from full exposure to the environment. It occurs in a wetted or buried environment when a crevice or area of stagnant or low flow exists that allows a corrosive environment to develop in a component. It occurs most frequently in joints and connections, or points of contact between metals and nonmetals, such as gasket surfaces, lap joints, and under bolt heads. Even when it is possible to avoid crevices by design, they may form spontaneously in service by precipitation of solid particles, biofouling, or coating disbondment. Carbon steel, cast iron, low-alloy steels, SS, copper, and nickel-based alloys are all susceptible to crevice corrosion. Steel can be subject to crevice corrosion in some cases after lining/cladding degradation. See discussion of differential aeration corrosion.
Cyclic loading	Cyclic loading can cause cracking by periodic application of mechanical and thermal loads on a component. Examples of cyclic loading are pressure and thermally induced loads due to thermal-hydraulic transients of piping components. Fatigue cracking is a typical result of cyclic loadings on metal components.
Differential aeration corrosion	Differential aeration corrosion is a type of corrosion that occurs when oxygen concentrations vary across a metal’s surface, creating an anode and a cathode. The higher oxygen concentration area becomes the cathode, and the lower oxygen concentration area becomes the anode that is being subjected to loss of material. Varying oxygen concentrations may be found in metals that are buried (different soil densities or air-to-soil interfaces); that contain certain types of joints, crevices, and cracks; that are partially submerged (air-to-water interface); and in piping that has internal deposits (biotic or inorganic). Any of the aging management programs (AMPs) used to detect loss of material due to general, pitting, or crevice corrosion can also detect loss of material due to differential aeration corrosion.
Distortion	The aging mechanism of distortion (as associated with component supports in the GALL-SLR Report, Chapter III.B2) can be caused by time-dependent strain or by gradual elastic and plastic deformation of metal that is under constant stress at a value lower than its normal yield strength.
Elastomer or polymer degradation	Elastomer or polymer degradation is an encompassing term related to various aging mechanisms that result in hardening or loss of the strength of elastomers or polymers. Degradation can occur due to thermal aging (elevated temperature over about 35 °C [95 °F]), exposure to ozone, oxidation, photolysis (due to ultraviolet light), and radiation. [Ref. 9] Degradation may include mechanisms such as cracking, crazing, fatigue breakdown, abrasion, chemical attacks, and change in material properties. [Ref. 27, 28]

Term	As Used in this Document
Electrical transients	An electrical transient is a stressor caused by a voltage spike that can contribute to aging degradation. Certain types of high-energy electrical transients can contribute to electromechanical forces, ultimately resulting in fatigue or loosening of bolted connections. Transient voltage surges are a major contributor to the early failure of sensitive electrical components.
Elevated temperature	Elevated temperature is referenced as an aging mechanism only in the context of light water reactor (LWR) containments (GALL-SLR Chapter II). In concrete, the reduction of strength and modulus can be attributed to elevated temperatures (>66 °C [>150 °F] general; >93 °C [>200 °F] local).
Erosion	Erosion is the progressive loss of material due to the mechanical interaction between a surface and a moving fluid. Different forms of erosion include cavitation, flashing, droplet impingement, and solid particle impingement.
Erosion settlement	Erosion settlement is the subsidence of a containment structure that may occur due to changes in the site conditions, (e.g., erosion or changes in the water table). The amount of settlement depends on the foundation material. [Ref. 24] Another synonymous term is "erosion of the porous concrete subfoundation."
Erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	In earthen water-control structures, the loss of material and loss of form can result from erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage.
Fatigue	Fatigue is a phenomenon leading to fracture under repeated or fluctuating stresses that have a maximum value less than the tensile strength of the material. Fatigue fractures are progressive and grow under the action of the fluctuating stress. Fatigue due to vibratory and cyclic thermal loads is defined as the structural degradation that can occur from repeated stress/strain cycles caused by fluctuating loads (e.g., from vibratory loads) and temperatures, giving rise to thermal loads. After repeated cyclic loading of sufficient magnitude, microstructural damage may accumulate, leading to macroscopic crack initiation at the most vulnerable regions. Subsequent mechanical or thermal cyclic loading may lead to growth of the initiated crack. Vibration may result in component cyclic fatigue, as well as in cutting, wear, and abrasion, if left unabated. Vibration is generally induced by external equipment operation. It may also result from flow resonance or movement of pumps or valves in fluid systems. Crack initiation and growth resistance are governed by factors including stress range, mean stress, loading frequency, surface condition, and the presence of deleterious chemical species. [Ref. 29]

Term	As Used in this Document
Flow-accelerated corrosion (FAC)	FAC is a corrosion mechanism that results in wall thinning of carbon steel components exposed to moving, high-temperature, low-oxygen water, such as PWR primary and secondary water, and boiling water reactor (BWR) reactor coolant. FAC is the result of the dissolution of the surface film of the steel, which is transported away from the site of dissolution by the movement of water. [Ref. 30]
Fouling	Fouling is an accumulation of deposits on the surface of a component or structure. This term includes accumulation and growth of aquatic organisms on submerged surfaces or the accumulation of deposits (usually inorganic). Fouling can be categorized as particulate fouling (e.g., sediment, silt, dust, eroded coatings, and corrosion products), biofouling, or macro fouling (e.g., delaminated coatings, debris). Biofouling can be caused by either macro organisms (e.g., barnacles, Asian clams, zebra mussels, or others found in freshwater and saltwater) or microorganisms (e.g., algae, bacteria, fungi). Fouling from tuberculation can be due to either inorganic (localized electrochemical corrosion) or organic (microbiological) causes. Fouling can result in a reduction of heat transfer, loss of material, or flow blockage and can occur in air, condensation, lubricating oil, or various water environments.
Freeze-thaw, frost action	Repeated freezing and thawing can cause severe degradation of concrete, characterized by scaling, cracking, and spalling. The cause is water freezing within the pores of the concrete, creating hydraulic pressure. If unrelieved, this pressure will lead to freeze-thaw degradation. If the temperature cannot be controlled, other factors that enhance the resistance of concrete to freeze-thaw degradation are (1) adequate air content (i.e., within ranges specified in ACI 301-84), (2) low permeability, (3) protection until adequate strength has developed, and (4) surface coating applied to frequently wet-dry surfaces. [Ref. 24, 31]
Fretting	Fretting is a wear process that occurs at the interface between contacting surfaces that experience a slight, differential oscillatory movement. Fretting can lead to loss of material.

Term	As Used in this Document
Galvanic corrosion	Galvanic corrosion is accelerated corrosion of a metal because of an electrical contact with a more noble metal or nonmetallic conductor in a corrosive electrolyte. It is also called bimetallic corrosion, contact corrosion, dissimilar metal corrosion, or two-metal corrosion. For example, galvanic corrosion is an applicable aging mechanism for steel materials coupled to more noble metals in heat exchangers; galvanic corrosion of copper is of concern when coupled with the nobler SS. Galvanic corrosion was removed from the aging management review (AMR) item tables as a specific aging mechanism. The most effective means of mitigating or preventing galvanic corrosion involve design and maintenance activities. For example: (1) selecting dissimilar metals that are as close to each other in the galvanic series, (2) avoiding localized small anodes and large cathodes, (3) instituting means to insulate the dissimilar metals from each other, (4) applying coatings, and (5) employing sacrificial anodes. Although galvanic corrosion has been removed from the AMR item tables as a specific aging mechanism, several AMPs support the mitigation or prevention of galvanic corrosion. For example: GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," manages loss of coating integrity. A licensee experienced accelerated galvanic corrosion when loss of coating integrity occurred in the vicinity of carbon steel components attached to AL6XN components. [Ref. 32] GALL-SLR Report AMP XI.M10, "Boric Acid Corrosion," inspections can detect boric acid residue spanning dissimilar metals, which can result in a galvanic corrosion cell. A licensee experienced galvanic corrosion of a steel nozzle when boric acid residue spanned the steel nozzle and attached SS piping. The galvanic corrosion resulted in corrosion rates 1.5 times higher than expected. [Ref. 33] Cracking or pitting of SS or nickel alloy cladding can lead to localized galvanic attack. AMPs XI.M32, "One-Time Inspection," and XI.M21A, "Closed Treated Water Systems," are used to detect cracking due to stress corrosion cracking (SCC) and loss of material due to pitting and crevice corrosion for clad steel components. Any of the AMPs used to detect loss of material due to general, pitting, or crevice corrosion can also detect loss of material due to galvanic corrosion.
General corrosion	General corrosion, also known as uniform corrosion, proceeds at approximately the same rate over a metal surface.
Intergranular attack (IGA)	In austenitic SSs, the precipitation of chromium carbides, usually at grain boundaries, on exposure to temperatures of about 550–850 °C (1,022–1,562 °F), leaves the grain boundaries depleted of chromium and, therefore, susceptible to preferential attack (IGA) by a corroding (oxidizing) medium.
Intergranular stress corrosion cracking (IGSCC)	IGSCC is SCC in which the cracking occurs along grain boundaries.

Term	As Used in this Document
Irradiation-assisted stress corrosion cracking (IASCC)	Failure by intergranular cracking in aqueous environments of stressed materials exposed to ionizing radiation has been termed IASCC. Irradiation by high-energy neutrons can promote SCC by affecting material microchemistry (e.g., radiation-induced segregation of elements such as P, S, Si, and Ni to the grain boundaries), material composition and microstructure (e.g., radiation hardening), as well as water chemistry (e.g., radiolysis of the reactor water to make it more aggressive).
Leaching of calcium hydroxide and carbonation	Water passing through cracks, inadequately prepared construction joints, or areas that are not sufficiently consolidated during placing may dissolve some calcium-containing products (of which calcium hydroxide is the most-readily soluble, depending on the solution pH) in concrete. Once the calcium hydroxide has been leached away, other cementitious constituents become vulnerable to chemical decomposition, finally leaving only the silica and alumina gels behind with little strength. The water's aggressiveness in the leaching of calcium hydroxide depends on its salt content, pH, and temperature. This leaching action is effective only if the water passes through the concrete. [Ref. 24]
Low-temperature crack propagation (LTCP)	LTCP is IGSCC at low temperatures, ~54–77 °C (~130–170 °F).
Mechanical loading	Applied loads of mechanical origins rather than from other sources, such as thermal.
Mechanical wear	See *wear*.
Microbiologically influenced corrosion	Any of the various forms of corrosion induced by the presence and activities of microorganisms such as bacteria, fungi, and algae, and/or the byproducts of their metabolism. Degradation of material that is accelerated due to conditions under a biofilm or tubercle; for example, anaerobic bacteria that can set up an electrochemical galvanic reaction or inactivate a passive protective film, or acid-producing bacterial that might produce corrosive metabolites.
Moisture intrusion	Influx of moisture through any viable process.
Neutron irradiation embrittlement	Irradiation by neutrons results in embrittlement of carbon and low-alloy steels. It may produce changes in mechanical properties by increasing tensile and yield strengths with a corresponding decrease in fracture toughness and ductility. The extent of embrittlement depends on neutron fluence, temperature, and trace material chemistry. [Ref. 26]
Ohmic heating	Ohmic heating is induced by current flow through a conductor and can be calculated using the first principles of electricity and heat transfer. Ohmic heating is a thermal stressor and can be induced by conductors passing through electrical penetrations, for example. Ohmic heating is especially significant for power circuit penetrations. [Ref. 17]

Term	As Used in this Document
Outside diameter stress corrosion cracking (ODSCC)	ODSCC is SCC initiating in the outer diameter (secondary side) surface of steam generator tubes. The secondary side is part of the secondary system consisting of the shell side of the steam generator, high- and low-pressure turbines, moisture/separator reheaters, main electrical stages, and interconnecting piping. This differs from primary water stress corrosion cracking, which describes inner diameter (steam generator primary side) initiated cracking. [Ref. 23]. The primary loop basically consists of the reactor vessel, reactor coolant pumps, pressurizer steam generator tubes, and interconnecting piping.
Overload	Overload is one of the aging mechanisms that can cause loss of mechanical function in Class 1 piping and components, such as constant and variable load spring hangers, guides, stops, sliding surfaces, and vibration isolators, fabricated from steel or other materials, such as Lubrite®.
Oxidation	Oxidation involves two types of reactions: (1) an increase in valence resulting from a loss of electrons, or (2) a corrosion reaction in which the corroded metal forms an oxide. [Ref. 27]
Photolysis	Chemical reactions induced or assisted by light.
Pitting corrosion	Localized corrosion of a metal surface, confined to a point or small area, which takes the form of cavities called pits.
Presence of any salt deposits	The surface contamination (and increased electrical conductivity) resulting from the aggressive environment associated with the presence of salt deposits can degrade high-voltage insulator quality. Although this aging mechanism may be due to temporary, transient environmental conditions, the net result may be long-lasting and cumulative for plants located in the vicinity of saltwater bodies.
Primary water stress corrosion cracking (PWSCC)	PWSCC is an intergranular cracking mechanism that requires the presence of high applied and/or residual stress, susceptible microstructure (few intergranular carbides), and also high temperatures. This aging mechanism is most likely a factor for nickel alloys in the PWR environment. [Ref. 22]
Radiation hardening, temperature, humidity, sustained vibratory loading	Reduction or loss of isolation function in polymeric vibration isolation elements can result from a combination of radiation hardening, temperature, humidity, and sustained vibratory loading.
Radiation-induced oxidation	Two types of reactions that are affected by radiation are (1) an increase in valence resulting from a loss of electrons, or (2) a corrosion reaction in which the corroded metal forms an oxide. This is a very limited form of oxidation and is referenced in GALL-SLR Chapter VI for metal enclosed bus insulation. [Ref. 27]
Radiolysis	Radiolysis is a chemical reaction induced or assisted by radiation. Radiolysis and photolysis aging mechanisms can occur in ultraviolet-sensitive organic materials.

Term	As Used in this Document
Reaction with aggregate	The presence of reactive alkalis in concrete can lead to subsequent reactions with aggregates that may be present. These alkalis are introduced mainly by cement, but also may come from admixtures, salt-contamination, seawater penetration, or solutions of deicing salts. These reactions include alkali-silica reactions, cement-aggregate reactions, and aggregate-carbonate reactions. These reactions may lead to expansion and cracking. [Ref. 14, 34]
Recurring internal corrosion	Recurring internal corrosion is identified by both the number of occurrences of internal aging effects with the same aging mechanism and the extent of degradation at each localized site. With regard to the number of occurrences, aging effects are considered recurring if the search of plant-specific operating experience (OE) reveals repetitive occurrences (e.g., one per refueling outage cycle that has occurred over three or more sequential or nonsequential cycles for a 10-year OE search, or two or more sequential or nonsequential cycles for a 5-year OE search) of aging effects with the same aging mechanism. With regard to the extent of degradation, aging effects are considered recurring if the aging effect results in the component not meeting either plant-specific acceptance criteria or experiencing a reduction in wall thickness of greater than 50% (regardless of the minimum wall thickness). Recurring internal corrosion is evaluated based on the aging mechanisms observed. For example, multiple occurrences of loss of material due to microbiologically influenced corrosion, pitting, or galvanic corrosion would be considered three separate occurrences of aging mechanisms that could be grouped as recurring internal corrosion but that would be evaluated separately.
Restraint shrinkage	Restraint shrinkage can cause cracking in concrete transverse to the longitudinal construction joint.
Selective leaching	Selective leaching is a type of corrosion in which one or more elements are preferentially removed from an alloy or metallic phase. Selective leaching is also called dealloying but it might be referred to by material-specific names (e.g., dezincification, dealuminification, graphitic corrosion). A dealloyed component often retains its shape and may visually appear to be unaffected; however, the effective cross section of the component has been reduced. The dealloyed volume is often composed of various amounts of unaffected phases, corrosion products, redeposited material, and a network of interconnected voids. The dealloyed volume does not have mechanical properties that can be credited for structural integrity.
Service-induced cracking or other concrete aging mechanisms	Cracking of concrete under load over time of service (e.g., from shrinkage or creep, or other concrete aging mechanisms) that may include freeze-thaw, leaching, aggressive chemicals, reaction with aggregates, corrosion of embedded steels, elevated temperatures, irradiation, abrasion, and cavitation. [Ref. 20]
Settlement	This term is referenced as an aging mechanism in GALL-SLR Chapter II, “Containment Structures.” Settlement of a containment structure may occur due to changes in the site conditions (e.g., water table, etc.). The amount of settlement depends on the foundation material. [Ref. 23]

Term	As Used in this Document
Stress corrosion cracking	SCC is the cracking of a metal produced by the combined action of corrosion and tensile stress (applied or residual), especially at elevated temperatures. SCC is highly chemically specific in that certain alloys are likely to undergo SCC only when exposed to a small number of chemical environments. For PWR internal components, in Chapters IV.B2, IV.B3 and IV.B4, SCC includes intergranular SCC, transgranular SCC, primary water SCC, and low-temperature crack propagation as aging mechanisms.
Stress relaxation	Many of the bolts in reactor internals are stressed to a cold initial preload. When subject to high operating temperatures, over time these bolts may loosen and the preload may be lost. Radiation can also cause stress relaxation in highly stressed members such as bolts. [Ref. 15]. Relaxation in structural steel anchorage components can be an aging mechanism contributing to the aging effect of loss of prestress.
Surface contamination	Contamination of the surfaces by corrosive constituents or fouling.
Sustained vibratory loading	Vibratory loading over time.
Thermal aging embrittlement	Also termed “thermal aging” or “thermal embrittlement.” At operating temperatures of 260 to 343 °C (500 to 650 °F), cast austenitic stainless steel (CASS) exhibits a spinoidal decomposition of the ferrite phase into ferrite-rich and chromium-rich phases. This may give rise to significant embrittlement (reduction in fracture toughness), depending on the amount, morphology, and distribution of the ferrite phase and the composition of the steel. Thermal aging of materials other than CASS is a time- and temperature-dependent degradation mechanism that decreases material toughness. It includes temper embrittlement and strain aging embrittlement. Ferritic and low-alloy steels are subject to both of these types of embrittlement, but wrought SS is not affected by either of these processes [Ref. 26].
Thermal effects, gasket creep, and self-loosening	Loss of preload due to gasket creep, thermal effects (including differential expansion and creep or stress relaxation), and self-loosening (which includes vibration, joint flexing, cyclic shear loads, thermal cycles). [Ref. 18, 19]
Thermal and mechanical loading	Loads (stress) due to mechanical or thermal (temperature) sources.
Thermal degradation of organic materials	Organic materials, in this case, are polymers. This category includes short-term thermal degradation and long-term thermal degradation. Thermal energy absorbed by polymers can result in crosslinking and chain scission. Crosslinking will generally result in aging effects such as increased tensile strength and hardening of material, with some loss of flexibility and eventual decrease in elongation-at-break and increased compression set. Scission generally reduces tensile strength. Other reactions that may occur include crystallization and chain depolymerization.

Term	As Used in this Document
Thermal fatigue	Fatigue is the progressive and localized structural damage that occurs when a material is subjected to cyclic loading. The maximum stress values are less than the ultimate tensile stress limit, and may be below the yield stress limit of the material. Higher temperatures generally decrease fatigue strength. Thermal fatigue can result from phenomena such as thermal loading, thermal cycling, where there is cycling of the thermal loads, and thermal stratification and turbulent penetration. Thermal stratification is a thermo-hydraulic condition with a definitive hot and cold water boundary that induces thermal fatigue of the piping. Turbulent penetration is a thermo-hydraulic condition where hot and cold water mix as a result of turbulent flow conditions, leading to thermal fatigue of the piping. The GALL-SLR Report AMP XI.M32, “One-Time Inspection,” inspects for cracking induced by thermal stratification, and for turbulent penetration via volumetric (radiographic testing or ultrasonic) techniques.
Thermoxidative degradation of organics/thermoplastics	Degradation of organics/thermoplastics via oxidation reactions (loss of electrons by a constituent of a chemical reaction) and thermal means (see *thermal degradation of organic materials*). [Ref. 25]
Transgranular stress corrosion cracking (TGSCC)	TGSCC is SCC in which cracking occurs across the grains.
Void swelling	Vacancies created in reactor (metallic) materials as a result of irradiation may accumulate into voids that may, in turn, lead to changes in dimensions (swelling) of the material. Void swelling may occur after an extended incubation period.
Water trees	Water trees occur when the insulating materials are exposed to long-term electrical stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. The growth and propagation of water trees is somewhat unpredictable. Water treeing is a degradation and long-term failure phenomenon.
Wear	Wear is defined as the removal of surface layers due to relative motion between two surfaces or under the influence of hard, abrasive particles. Wear occurs in parts that experience intermittent relative motion, frequent manipulation, or in clamped joints where relative motion is not intended but may occur due to a loss of the clamping force. [Ref. 26]. Loss of material due to wear can also occur in polymeric components buried in soil containing deleterious materials that move over time due to seasonal change effects on the soil. In the case of a CFRP-repaired pipe, wear occurs when the CFRP top layer shows material loss by erosion caused by fluid flowing through the pipe.
Weathering	Weathering is the mechanical or chemical degradation of external surfaces of materials when exposed to an outside environment.
Wind-induced abrasion	(See *abrasion*) The fluid carrier of abrading particles is wind rather than water/liquids.

ACI = American Concrete Institute; AMP = aging management program; AMR = aging management review; BWR = boiling water reactor; CASS = cast austenitic stainless steel; FAC = flow-accelerated corrosion; GALL-SLR = Generic Aging Lessons Learned for Subsequent License Renewal; IGA = intergranular attack; IASCC = irradiation assisted stress corrosion cracking; IGSCC = intergranular stress corrosion cracking; LTCP = low-temperature crack propagation; LWR = light water reactor; ODSCC = outside diameter stress corrosion cracking; OE = operating experience; PWR = pressurized water reactor; PWSCC = primary water stress corrosion cracking; SCC = stress corrosion cracking; SS = stainless steel; TG = transgranular stress corrosion cracking.

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CHAPTER X

AGING MANAGEMENT PROGRAMS THAT MAY BE USED TO DEMONSTRATE ACCEPTABILITY OF TIME-LIMITED AGING ANALYSES IN ACCORDANCE WITH 10 CFR 54.21(C)(1)(III)

X AGING MANAGEMENT PROGRAMS THAT MAY BE USED TO DEMONSTRATE ACCEPTABILITY OF TIME-LIMITED AGING ANALYSES IN ACCORDANCE WITH 10 CFR 54.21(C)(1)(III)

This chapter of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report provides the following aging management programs that are used to demonstrate acceptance of specific types of generic time-limited aging analyses in accordance with the requirements in Title 10 of the *Code of Federal Regulations* (10 CFR) 54.21(c)(1)(iii)(TN4878) and to demonstrate that the impacts of the effects of aging on the intended functions of the components in the analyses will be adequately managed during the subsequent license renewal period:

X.E1 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

X.MI FATIGUE MONITORING

X.M2 NEUTRON FLUENCE MONITORING

X.S1 CONCRETE CONTAINMENT UNBONDED TENDON PRESTRESS

TABLE X-01 FSAR SUPPLEMENT SUMMARIES FOR GALL-SLR REPORT CHAPTER X AGING MANAGEMENT PROGRAMS

X.E ELECTRICAL

X.E1 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

Program Description

The U.S. Nuclear Regulatory Commission (NRC) has established nuclear station environmental qualification (EQ) requirements in Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50 (TN249), Appendix A, Criterion 4, and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments (that is, the areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident [LOCA], high-energy line break and post-LOCA environment) are qualified to perform their safety functions in those harsh environments after the effects of inservice (operational) aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ.

For equipment located in a harsh environment, the objective of EQ is to demonstrate with reasonable assurance that electric equipment important to safety, for which a qualified life has been established, can perform its safety function(s) without experiencing common cause failures before, during, or after applicable design basis events.

For equipment located in a mild environment (an environment that at no time would be significantly more severe than the environment occurring during normal operation, including anticipated operational occurrences as defined in 10 CFR 50.49), the demonstration that the equipment meets its functional requirements during normal environmental conditions and anticipated operational occurrences is in accordance with the plant design and licensing basis. Equipment important to safety located in a mild environment is not part of an EQ program per 10 CFR 50.49(c). Documents that demonstrate that a component is qualified or designed for a mild environment include design/purchase specifications, seismic test qualification reports, an evaluation, or a certificate of conformance.

Operating plants requesting subsequent license renewal shall meet the qualification requirements of 10 CFR 50.49 and license renewal aging management provisions of 10 CFR Part 54 (TN4878) for certain electrical equipment important to safety. 10 CFR 50.49 defines the scope of equipment to be included in an EQ program, requires the preparation and maintenance of a list of in-scope equipment (e.g., gaskets, seals, O-rings, etc.), and requires the preparation and maintenance of a qualification file that contains the qualification report, with applicable equipment performance specifications, electrical characteristics, and the environmental conditions to which the equipment could be subjected. Licensees are required to maintain a record of qualification in auditable form (10 CFR 50.49(j)) for the entire period during which each covered item is installed in the nuclear power plant or is stored for future use.

Additionally, 10 CFR 50.49(e) states that electric equipment qualification programs must include and be based on temperature, pressure, humidity, chemical effects, radiation, aging, submergence, and consideration of synergistic effects. The requirements of 10 CFR 50.49(e) also include the application of margins to account for unquantified uncertainties, including production variations, and inaccuracies in test instruments. These margins are in addition to any conservatism applied during the derivation of local environmental conditions of the equipment unless these conservatisms can be quantified and shown to contain the appropriate margins. The aging provisions contained in 10 CFR 50.49(e)(5) require, in part, consideration of all significant types of aging degradation (e.g., plant-specific operational aging that includes thermal, radiation, vibration, and cyclic aging) that can have an effect on the functional capability of the equipment.

EQ programs manage equipment thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) (TN249) qualification methods. Four methods are established by 10 CFR 50.49(f) to demonstrate qualification for aging and accident conditions:

- Testing an identical item of equipment under identical conditions or under similar conditions with a supporting analysis to show that the equipment to be qualified is acceptable.
- Testing a similar item of equipment with a supporting analysis to show that the equipment to be qualified is acceptable.
- Experience with identical or similar equipment under similar conditions with a supporting analysis to show that the equipment to be qualified is acceptable.
- Analysis in combination with partial type-test data that supports the analytical assumptions and conclusions [is acceptable.]

Additionally, 10 CFR 50.49(k) and (i) permit different qualification criteria to apply based on plant and electrical equipment vintage.

Supplemental EQ regulatory guidance for compliance with these different qualification criteria is provided in the Division of Operating Reactors (DOR) Guidelines; “Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors”; NUREG–0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment (Category 1 and Category 2 requirements)”; and Regulatory Guide (RG) 1.89, Revision 1, “Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants,” as applicable. Compliance with 10 CFR 50.49 provides reasonable assurance that the equipment can perform its intended function during accident conditions after experiencing the effects of inservice aging.

For equipment preconditioned and tested to less than an end-of-installed life condition (i.e., preconditioned to a shorter designated life), 10 CFR 50.49(e)(5) requires the equipment to be replaced or refurbished at the end of its designated life unless additional life is established through ongoing qualification.

Electrical equipment important to safety to be included in a 10 CFR 50.49 EQ program is specified under 10 CFR 50.49(b). A list of environmentally qualified electrical equipment important to safety is required under 10 CFR 50.49(d). Plant systems, structures, and components within the scope of license renewal established under 10 CFR 50.49 that are within scope of license renewal per 10 CFR 54.4(a)(3) (TN4878) and have an associated time-limited aging analysis (TLAA) under 10 CFR 54.3(a) require an evaluation to demonstrate that the TLAA analysis satisfies 10 CFR 54.21(c)(1)iii.

Along with Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP X.E1, plant EQ programs that implement the requirements of 10 CFR 50.49 (as further defined and clarified by the DOR Guidelines, NUREG–0588, and RG 1.89) demonstrate the acceptability of the TLAA analysis under 10 CFR 54.21(c)(1) and are considered an acceptable aging management program (AMP) for the subsequent period of extended operation.

Environmental Qualification – Reanalysis

Reanalysis evaluates the original attributes, assumptions, and conservatisms for environmental conditions and other factors of an aging evaluation to demonstrate that the qualified life of the equipment can be extended. Reanalysis of equipment qualified under the program requirements of 10 CFR 50.49(e) (TN249) is performed as part of an EQ program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. These attributes are discussed in the “Environmental Qualification Equipment Reanalysis Attributes” section below.

Environmental Qualification Equipment Reanalysis Attributes

The reanalysis of an existing aging evaluation is normally performed to extend the qualification by reevaluating original attributes, assumptions, and conservatisms in environmental conditions and other factors to identify excess conservatisms incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of electrical equipment is performed pursuant to 10 CFR 50.49(e) as part of an EQ program. While an electrical equipment life-limiting condition may be due to thermal, radiation, or cyclical aging, most electrical equipment aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed service conditions or unrealistically low activation energy. The reanalysis of an aging evaluation is performed according to the station's quality assurance (QA) program requirements, which require the verification of assumptions and conclusions including the maintenance of required margins.

As already noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. These attributes are discussed below.

- ***Analytical Methods:*** The analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose that includes normal radiation dose for the projected installed life plus accident radiation dose. For subsequent license renewal, one acceptable method of establishing the 80-year normal radiation dose is to multiply the initial 40-year normal radiation dose by two. The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis.

- ***Data Collection and Reduction Methods:*** The identification of excess conservatism in electrical equipment service conditions used in the prior aging evaluation is the chief method used for a reanalysis. For example, temperature data, associated margins, and uncertainties used in an equipment EQ evaluation may be based on anticipated plant design temperatures found to be conservative compared to actual plant temperature data. When used, plant environmental data may be obtained from monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, dedicated monitors for EQ equipment, or combinations of these sources. The environmental data gathering and analysis method can be used to identify conservatism in the original qualification and justify the additional qualified life for the EQ equipment. Any changes in material activation energy values included as part of a reanalysis are justified by the applicant on a component-specific basis.

- ***Underlying Assumptions:*** EQ equipment aging evaluations account for environmental changes occurring due to plant modifications, seasonal changes, and events. A reanalysis demonstrates that adequate margin is maintained consistent with the original analysis in accordance with 10 CFR 50.49 (TN249). 10 CFR 50.49 requires further consideration of certain margins and accounting for unquantified uncertainties such as diffusion-limited oxidation, activation energy, synergistic effects, inverse temperature, and dose rate effects. Reanalysis that uses initial qualification conservatisms and/or inservice environmental conditions (e.g., actual temperature and radiation conditions) are part of an EQ program.

Adverse Localized Environment

In most areas within a nuclear power plant, the actual operating environment (e.g., temperature, or radiation) is less severe than the plant design basis environment. However, in a limited number of localized areas, the actual environment may be more severe than the anticipated plant design basis environment. These localized areas are characterized as “adverse localized environments” that represent a limited plant area where the operating environment is significantly more severe than the plant design environment considered in the qualification for EQ equipment.

An adverse localized environment may increase the rate of aging or have an adverse effect on the basis for equipment qualification. An adverse localized environment is an environment that exceeds the most limiting qualified condition for temperature or radiation for the component material. EQ electrical equipment may degrade more rapidly than expected when exposed to an adverse localized environment.

Adverse localized environments are identified using an integrated approach. This approach includes, but is not limited to, the following: the review of (1) EQ program radiation levels and temperatures, (2) recorded information from equipment or plant instrumentation, (3) as-built and field walkdown data (e.g., cable routing data base), (4) a plant spaces scoping and screening methodology, (5) plant modifications (e.g., power uprate), and (6) relevant plant-specific and industry operating experience (OE). The OE includes, but is not limited to the following:

- Identification of work practices that have the potential to subject in-scope EQ equipment to an adverse localized environment (e.g., influence of maintenance activity that removes thermal insulation and restoration from hot pipes).
- Corrective actions for in-scope EQ equipment involving end-of-installed life, designated life, or qualified life (current operating term).
- Observations from previous walkdowns including visual inspections.
- Environmental monitoring (e.g., long-term periodic environmental monitoring of EQ equipment – temperature or radiation).
- Inspection of accessible passive EQ equipment and the evaluation of the equipment environment to identify electrical equipment subjected to an adverse localized environment. The impact of aging on accessible EQ equipment located in an adverse localized environment is evaluated and represents, with reasonable assurance, both accessible and inaccessible EQ equipment age degradation.

The inspection portion of the EQ of the Electric Components program is considered a visual inspection performed from the floor, with the use of scaffolding, as available, and without the opening of junction boxes, pull boxes, or terminal boxes. The purpose of the visual inspection is to identify adverse localized environments (employing diagnostic tools such as thermography as applicable). The accessible, passive EQ components located in these adverse localized environments are then visually inspected, which, depending on the visual inspection results, may require further inspection using scaffolding or other means (e.g., opening of junction boxes, pull boxes, accessible pull points, panels, terminal boxes, and junction boxes) to assess EQ electrical equipment aging degradation. Passive EQ equipment subject to an adverse localized environment may result in surface abnormalities that are visually observable, such as cable jacket surface embrittlement, discoloration, cracking, melting, swelling, or surface contamination. Visual inspection can be used as an indicator of age degradation.

Adverse conditions identified during periodic inspections or by operational or maintenance activities that affect the operating environment of EQ equipment are evaluated and appropriate corrective actions are taken, which may include changes in qualification bases and conclusions (e.g., changes in qualified life).

In-scope accessible passive EQ electrical equipment is inspected at least once every 10 years to identify EQ electrical equipment subjected to an adverse localized environment. The first periodic inspection is to be performed prior to the subsequent period of extended operation.

Acceptance Criteria and Corrective Actions

Reanalysis of an aging evaluation is used to extend the qualification of the component. If the qualification cannot be extended by reanalysis, the equipment is refurbished, replaced, or requalified prior to exceeding its current qualified life. A reanalysis is performed in a timely manner to ensure sufficient time is available to refurbish, replace, or requalify the equipment if the result is unfavorable.

A modification of the qualified life by reanalysis must demonstrate that adequate margin is maintained consistent with the original analysis, including unquantified uncertainties established in the original EQ equipment aging evaluation.

Environmental Qualification – Ongoing Qualification

Ongoing qualification, for the purposes of this document, is defined as the process of requalifying a component through activities similar to the original qualification, which may include testing, type testing, or applying a monitoring program. When assessed, if margins, conservatisms, or assumptions do not support extending the qualified life, the following methods may be used:

- the retention and continued aging of a test sample from the original EQ test program with demonstration that the qualified life is bounding for the subsequent period of extended operation;
- the removal and type testing of additional EQ equipment installed in identical service conditions with a greater period of operational aging;
- a monitoring program that requires EQ equipment characteristics subject to aging degradation to be monitored at specific intervals and compared to specified acceptance criteria. The acceptance criteria are based on the capability of post-aging characteristics for the EQ equipment to retain functional properties during and after enduring the design bases environment, as applicable. Condition monitoring intervals are established to prevent age degradation beyond the acceptance criteria prior to taking corrective action.

The above-listed methods are considered ongoing qualification. Other methods or approaches may be acceptable. A modification to extend qualified life must be justified and must include program documentation and auditable evidence that adequate margin is maintained consistent with the original analysis, including unquantified uncertainties established during the original EQ equipment aging evaluation.

Evaluation and Technical Basis

1. ***Scope of Program:*** EQ programs apply to certain electrical equipment that is important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49 (TN249) and RG 1.89, Revision 1. Certain mechanical components associated with in-scope electrical equipment (e.g., gaskets, seals, O-rings, etc.) should be included. Plant EQ programs along with GALL-SLR Report AMP X.E1 demonstrate the acceptability of the EQ electrical equipment TLAA under 10 CFR 54.21(c)(1)(TN4878).

2. ***Preventive Actions:*** 10 CFR 50.49 does not require actions that prevent aging effects. EQ program actions that could be viewed as being preventive actions include (1) establishing the equipment service condition tolerance and aging limits (e.g., qualified life or condition limit) and (2) where applicable, requiring specific installation, inspection, monitoring, or periodic maintenance actions to maintain electrical equipment aging within the bounds of the qualification basis (e.g., identification of adverse localized environments or shielding for temperature and/or radiation).

3. ***Parameters Monitored or Inspected:*** Qualified life is not based on condition or performance monitoring. However, pursuant to RG 1.211 and RG 1.89, Revision 1, such monitoring programs are an acceptable basis for modifying a qualified life to establish a revised qualified condition. Monitoring or inspection of certain environmental conditions, including adverse localized environments, or equipment parameters may be used to verify that the equipment is within the bounds of its qualification basis, or as a means of modifying the qualified life.

4. ***Detection of Aging Effects:*** 10 CFR 50.49 does not require the detection of aging effects for inservice EQ equipment. EQ program actions that could be viewed as actions that detect aging effects include (1) inspecting EQ equipment periodically with particular emphasis on monitoring or condition assessment and (2) monitoring plant environmental conditions or component parameters used to verify that the equipment is within the bounds of its EQ basis, including attributes, assumptions, and conservatisms for equipment/environmental conditions and other factors. Monitoring or inspection of certain environmental conditions or component parameters may provide a means of maintaining equipment qualified life.

   Visual inspection of accessible, passive EQ equipment is performed at least once every 10 years. The purpose of the visual inspection is to identify adverse localized environments that may affect qualified life. Potential adverse localized environments are evaluated through the applicant’s corrective action program. The first periodic visual inspection is to be performed prior to the subsequent period of extended operation.

5. ***Monitoring and Trending:*** 10 CFR 50.49 (TN249) does not require monitoring and trending of component condition or the performance parameters of inservice equipment to manage the effects of aging. Monitoring, trending, or inspection of certain environmental, condition, or component parameters may be used to verify that EQ equipment is within the bounds of its qualification basis, or as a means of modifying the qualification.

6. ***Acceptance Criteria:*** An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of intended function.

10 CFR 50.49 acceptance criteria require that inservice EQ equipment is maintained within the bounds of its qualification basis, including its established qualified life and continued qualification for the projected accident conditions. 10 CFR 50.49 requires refurbishment, replacement, or requalification prior to exceeding the qualified life of each installed component. When monitoring is used to modify equipment qualified life, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods.

Visual inspection results show that accessible passive EQ equipment is free from unacceptable surface abnormalities that may indicate aging degradation.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

If an EQ component is found to be outside the bounds of its qualification basis, corrective actions are implemented in accordance with the station's corrective action program. When an unexpected adverse localized environment or condition is identified during operational or maintenance activities that affects the qualification of electrical equipment, the affected EQ equipment is evaluated and appropriate corrective actions are taken, which may include changes to the qualified life.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** EQ programs include consideration of OE to modify qualification bases and conclusions, including qualified life such that the impact on the EQ program is evaluated and any necessary actions or modifications to the program are performed. Compliance with 10 CFR 50.49 provides reasonable assurance that EQ equipment can perform its intended function during accident conditions after experiencing the effects of operational aging.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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10 CFR 54.21, “Contents of Application—Technical Information.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015. 10 CFR Part 54-TN4878

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X.M MECHANICAL

X.M1 FATIGUE MONITORING

Program Description

This aging management program (AMP) provides an acceptable basis for managing structures and components (SCs) that are the subject of fatigue or cycle-based time-limited aging analyses (TLAAs) or other analyses that assess fatigue or cyclical loading, in accordance with the requirements in Title 10 of the *Code of Federal Regulations* (10 CFR) 54.21(c)(1)(iii). Examples of cycle-based fatigue analyses for which this AMP may be used include, but are not limited to the following: (1) cumulative usage factor (CUF) analyses or their equivalent (e.g., I_t-based fatigue analyses, as defined in specific design codes) that are performed in accordance with American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) requirements for specific mechanical or structural components; (2) fatigue analysis calculations for assessing environmentally assisted fatigue; (3) implicit fatigue analyses, as defined in the United States of America Standards (USAS) WB31.1 design code or ASME Code Section III rules for Class 2 and Class 3 components; (4) fatigue flaw growth analyses that are based on cyclical loading assumptions; (5) fracture mechanics analyses that are based on cycle-based loading assumptions; and (6) fatigue waiver or exemption analyses that are based on cycle-based loading assumptions. This program may be used for fatigue analyses that apply to mechanical or structural components.

Fatigue of components is managed by monitoring one or more relevant fatigue parameters, which include, but are not limited to, the CUF factors, the environmentally adjusted cumulative usage factors (CUF_{en}), transient cycle limits, and the predicted flaw size (for a fatigue crack growth analysis). The limit of the fatigue parameter is established by the applicable fatigue analysis and may be a design limit, for example, from an ASME Code fatigue evaluation; an analysis-specific value, for example, based on the number of cyclic load occurrences assumed in a fatigue exemption evaluation; or the acceptable size of a flaw identified during an inservice inspection.

This program has two aspects, one that verifies the continued acceptability of existing analyses through cycle counting and another that provides periodically updated evaluations of the fatigue analyses to demonstrate that they continue to meet the appropriate limits. In the former, the program assures that the number of occurrences and the severity of each transient remain within the limits of the fatigue analyses, which in turn ensure that the analyses remain valid. For the latter, actual plant operating conditions monitored by this program can be used to inform updated evaluations of the fatigue analyses to ensure they continue to meet the design or analysis-specific limit. The program may include stress-based fatigue monitoring, in which operating temperatures, pressures, and other parameters are monitored and used to determine the effects of actual operating transients on the cumulative CUF and CUF_{en} for the analyzed components. Technical specification requirements may apply to these activities.

CUF is a computed parameter used to assess the likelihood of fatigue damage in components subjected to cyclic stresses. Crack initiation is assumed to begin in a mechanical or structural component when the CUF at a point on or in the component reaches the value of 1.0, which is the ASME Code Section III design limit on CUF values. (Note that other values may be used as CUF design limits; for example, values used for high-energy line break considerations.) In order to not exceed the design limit on CUF, the AMP may be used to directly monitor the number of transient occurrences (i.e., transient cycles) or to monitor applicable design transient parameters (e.g., temperatures, pressures, displacements, strains, flow rates, etc.) for components with stress-based fatigue calculations, such that the actual severity of each event is evaluated and used to compute the resulting fatigue usage factors for the affected component locations.

CUF_{en} is CUF adjusted to account for the effects of the reactor water environment on component fatigue life. For a plant, the effects of reactor water environment on fatigue are evaluated by assessing a set of sample critical components for the plant. Examples of critical components are identified in NUREG/CR–6260; however, plant-specific component locations in the reactor coolant pressure boundary may be more limiting than those considered in NUREG/CR–6260, and thus should also be considered. Environmental effects on fatigue for these critical components may be evaluated using the guidance in Regulatory Guide (RG) 1.207, Revision 1[1]; the bases in NUREG/CR–6909, Revision 0 ("average temperature" is used consistent with the clarification that was added to NUREG/CR–6909, Revision 1), or other subsequent U.S. Nuclear Regulatory Commission (NRC)-endorsed alternatives may be used. Similar to the monitoring of CUF limits, the AMP monitors and tracks the number of occurrences and the severity of each of the critical thermal and pressure transients for the selected components in order to maintain the CUF_{en} below the design limit of 1.0. This program also relies on the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M2, "Water Chemistry," to provide for monitoring of appropriate environmental parameters for calculating environmental fatigue multipliers (F_{en} values).

Some of the design fatigue analyses are implicit evaluations or fatigue waivers. Both of these analyses provide the basis for not requiring detailed fatigue analyses (e.g., CUF, CUF_{en}). Implicit evaluations specify allowable stress levels based on the number of anticipated full thermal range transient cycles. As an example, piping components designed to USAS American National Standards Institute (ANSI) B31.1 requirements and ASME Code Class 2 and 3 components designed to ASME Code Section III design requirements include implicit cycle-based maximum allowable stress range calculations. Fatigue waivers are based on transient cycle limits. Fatigue waivers may have been permitted such that a detailed fatigue calculation was not required if a component conformed to certain criteria, such as those established in ASME Code, Section III, NB-3222.4(d). The AMP monitors and tracks the number of critical thermal and pressure transient occurrences for the selected components and verifies that the severity of the monitored transients is bounded by the design transient definitions in order to ensure these implicit fatigue evaluations or fatigue waivers remain valid.

In some cases, flaw tolerance evaluations are used to establish inspection frequencies for components that, for example, exceed CUF or CUF_{en} fatigue limits. As an example, ASME Code, Section XI, Nonmandatory Appendix L provides guidance on the performance of fatigue flaw tolerance evaluations to determine the acceptability for continued service of reactor coolant system and primary pressure boundary components and piping subjected to cyclic loadings. In flaw tolerance evaluations, the predicted size of a postulated fatigue flaw, whose initial size is typically based on the resolution of the inspection method, is a computed parameter that is used to determine the appropriate inspection frequency. The AMP monitors and tracks the number of occurrences and severity of critical thermal and pressure transients for the selected components that are used in the fatigue flaw tolerance evaluations to verify that the inspection frequencies remain appropriate.

[1] If and when published as RG 1.207, Revision 1 Final.

When a flaw is identified by inservice inspection, ASME Code, Section XI, Nonmandatory Appendices A and C provide guidance on the performance of fatigue flaw crack growth evaluations to determine the acceptability of reactor coolant system pressure boundary components and piping subjected to cyclic loadings for continued service. In such a case, the predicted size of an identified flaw is a computed parameter suitable for determining the appropriate inspection frequency through a fatigue crack growth evaluation. The AMP monitors and tracks the number of occurrences and the severity of each of the critical thermal and pressure transients for the selected components that are used in the crack growth evaluations to verify that the inspection frequencies remain appropriate.

Evaluation and Technical Basis

1 ***Scope of Program:*** The scope includes the mechanical or structural components with a fatigue TLAA or other analysis that depends on the number of occurrences and severity of transient cycles. The program monitors and tracks the number of occurrences and the severity of thermal and pressure transients for the selected components to ensure that they remain within the plant-specific limits. The program ensures that the fatigue analyses remain within their allowable limits, thereby minimizing the likelihood of failures caused by fatigue-induced cracking of the components as a result of cyclic strains in the component's material. In addition, the program can be used to monitor actual plant operating conditions for component locations with stress-based fatigue calculations (i.e., stress-based CUF calculations) to perform updated evaluations of the fatigue analyses to ensure they continue to meet the design limits.

For the purposes of ascertaining the effects of the reactor water environment on fatigue, applicants include CUF_{en} calculations for a set of sample reactor coolant system components. This sample set includes the locations identified in NUREG/CR–6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR–6260. Plant-specific justification can be provided to demonstrate that calculations for the NUREG/CR–6260 locations do not need to be included. The environmental effects on fatigue for these critical components may be evaluated using the guidance in RG 1.207, Revision 1[2]; NUREG/CR–6909, Revision 0 (with "average temperature" used consistent with the clarification that was added to NUREG/CR–6909, Revision 1); or other subsequent NRC-endorsed alternatives. Component locations within the scope of this program are updated based on operating experience (OE), plant modifications, and inspection findings.

2 ***Preventive Actions:*** This program does not involve preventive actions.

3 ***Parameters Monitored or Inspected:*** The program monitors all applicable plant transients that cause cyclic strains and contribute to fatigue, as specified in the fatigue analyses, and monitors or validates appropriate environmental parameters that contribute to F_{en} values. The number of occurrences and the severity of the plant transients that contribute to the fatigue analyses for each component are monitored. For environmentally assisted fatigue calculations, chemistry parameters that provide inputs to F_{en} factors used in CUF_{en} calculations are monitored and tracked in accordance with this program or alternatively through implementation of the applicant's water chemistry program. More detailed monitoring of pressure, thermal, and water chemistry conditions at the component location may be performed to allow the fatigue analyses to be assessed for the specified critical locations.

[2] If and when published as RG 1.207, Revision 1 Final.

4 ***Detection of Aging Effects:*** The program uses applicant-defined activities or methods to track the number of occurrences and severity of design basis transient conditions, and any applicable plant operating conditions used to inform updated evaluations of the fatigue analyses. Monitoring of water chemistry parameters that are inputs to environmentally assisted fatigue calculations may be performed in accordance with the implementation of this AMP or an applicant's Water Chemistry program. Technical specification requirements may apply to these activities.

5 ***Monitoring and Trending:*** Monitoring and trending of the number of occurrences of each of the transient cycles and their severity are used to track the occurrences of all transients needed to ensure the continued acceptability of the fatigue analyses, or to update the analyses. Monitoring of plant operating conditions or water chemistry parameter conditions (i.e., as inputs for components with stress-based fatigue calculations or environmental fatigue calculations) is used to either verify the validity of the evaluations against their applicable design limits or else to update the evaluations, when necessary, of the fatigue analyses to ensure they continue to meet the design or analysis-specific limit. Trending is performed to ensure that the fatigue analyses are managed and that the fatigue parameter limits will not be exceeded during the subsequent period of extended operation, thereby minimizing the possibility of fatigue crack initiation of metal components caused by cyclic strains or water chemistry conditions. The program provides for revisions to the fatigue analyses or other corrective actions (e.g., revising augmented inspection frequencies) on an as-needed basis, if the values assumed for fatigue parameters are approached, transient severities exceed the design or assumed severities, transient counts exceed the design or assumed quantities, transient definitions have changed, unanticipated new fatigue loading events are discovered, or the geometries of components are modified.

6 ***Acceptance Criteria:*** The acceptance criterion is maintaining the value of all relevant fatigue parameters to values less than or equal to the limits established in the fatigue analyses, with consideration of reactor water environmental effects, where appropriate, as described in the program description and scope of program.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

The program also provides for corrective actions to prevent the appropriate limits of the fatigue analyses from being exceeded during the subsequent period of extended operation. Acceptable corrective actions include repair of the component, replacement of the component, and a more rigorous analysis of the component to demonstrate that the design limit will not be exceeded during the subsequent period of extended operation. In addition, a flaw tolerance analysis with appropriate (e.g., inclusion of environmental effects) crack growth rate curves and associated inspections performed in accordance with Appendix L of ASME Code Section XI is an acceptable correction action. For CUF_{en} analyses, the scope expansion includes consideration of other locations with the highest expected CUF_{en} values.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The program reviews industry experience relevant to fatigue cracking. Applicable OE relevant to fatigue cracking is to be considered when selecting the locations for monitoring. As discussed in the NRC Regulatory Issue Summary (RIS) 2008-30, the use of a certain simplified analysis methodology to demonstrate compliance with the ASME Code fatigue acceptance criteria could be nonconservative; therefore, a confirmatory analysis is recommended, if such a methodology is used. Furthermore, as discussed in NRC RIS 2011–14, the staff has identified concerns regarding the implementation of computer software packages used to calculate fatigue usage associated with plant transient operations.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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[3] If and when published as RG 1.207, Revision 1 Final.

X.M2 NEUTRON FLUENCE MONITORING

Program Description

This aging management program (AMP) provides a means of ensuring the validity of the neutron fluence analysis and related neutron fluence-based, time-limited aging analyses (TLAAs). In so doing, this AMP also provides an acceptable basis for managing aging effects attributable to neutron fluence in accordance with requirements in Title 10 of the *Code of Federal Regulations* (10 CFR) 54.21(c)(1)(iii). This program monitors neutron fluence for reactor pressure vessel (RPV) components and reactor vessel internal (RVI) components, and is used in conjunction with the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M31, “Reactor Vessel Material Surveillance.” Neutron fluence is a time-dependent input parameter for evaluating the loss of fracture toughness due to neutron irradiation embrittlement. Accurate neutron fluence values are also necessary to identify the RPV beltline region, for which neutron fluence is projected to exceed 1×10^{17} n/cm^2 (E > 1 MeV) during the subsequent period of extended operation.

Neutron fluence is an input to a number of RPV irradiation embrittlement analyses that are required by specific regulations in 10 CFR Part 50 (TN249). These analyses are TLAAs for subsequent license renewal applications (SLRAs) and are the topic of the acceptance criteria and review procedures in Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR) Section 4.2, “Reactor Vessel Neutron Embrittlement Analyses.” The neutron irradiation embrittlement TLAAs within the scope of this AMP include, but are not limited to, the following: (1) neutron fluence, (2) pressurized thermal shock analyses for pressurized water reactors, as required by 10 CFR 50.61 or alternatively (if applicable for the current licensing basis [CLB]) by 10 CFR 50.61a; (3) RPV upper-shelf energy analyses, as required by Section IV.A.1 of 10 CFR Part 50, Appendix G; and (4) pressure-temperature (P-T) limit analyses as required by Section IV.A.2 of 10 CFR Part 50, Appendix G, and controlled by plant technical specifications’ (TSs’) updating and reporting requirements (i.e., the 10 CFR 50.90 license amendment process for updates of P-T limit curves located in the TS limiting conditions of operation, or TS administrative control section requirements for updates of P-T limit curves that have been relocated to a P-T limits report).

The calculations of neutron fluence also factor into other analyses or technical report methodologies that assess irradiation-related aging effects. Examples include, but are not limited to the following: (1) determination of the RPV beltline as defined in Regulatory Issue Summary 2014-11, “Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components”; (2) evaluation of the susceptibility of RVI components to neutron radiation damage mechanisms, including irradiation embrittlement (IE), irradiation-assisted stress corrosion cracking (IASCC), irradiation-enhanced stress relaxation or creep (IESRC) and void swelling or neutron-induced component distortion; and (3) evaluation of the dosimetry data obtained from an RPV surveillance program.

Guidance on acceptable methods and assumptions for determining reactor vessel neutron fluence is described in the U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.190 (TN8000), “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” The methods developed and approved using the guidance contained in RG 1.190 are specifically intended for determining neutron fluence in the region of the RPV close to the active fuel region of the core and are not intended to apply to vessel regions significantly above and below the active fuel region of the core, or to RVI components.

Therefore, the use of RG 1.190-adherent methods to estimate neutron fluence for the RPV regions significantly above and below the active fuel region of the core and RVI components may require additional justification, even if the methods were approved by the NRC for RPV neutron fluence calculations. This program monitors in-vessel or ex-vessel dosimetry capsules and evaluates the dosimetry data, as needed. Such dosimetry capsules may be needed when the reactor surveillance program has exhausted the available capsules for in-vessel exposure.

Evaluation and Technical Basis

1 ***Scope of Program:*** The scope of the program includes RPV and RVI components that are subject to a neutron embrittlement TLAA or other analysis involving time-dependent neutron irradiation. The program monitors neutron fluence throughout the subsequent period of extended operation for determining the susceptibility of the components to IE, IASCC, IESRC, and void swelling or distortion. The use of this program also continues to ensure the adequacy of the neutron fluence estimates by (1) monitoring plant and core operating conditions relative to the assumptions used in the neutron fluence calculations, and (2) continuously updating the qualification database associated with the neutron fluence method as new calculational and measurement data become available for benchmarking. This program is used in conjunction with GALL-SLR Report AMP XI.M31, “Reactor Vessel Material Surveillance.”

Updated neutron fluence calculations, plant modifications, and RPV surveillance program data are used to identify component locations within the scope of this program, including the beltline region of the RPV. Applicable requirements in 10 CFR Part 50 (TN249) and, if appropriate, plant TSs related to calculating neutron fluence estimates and incorporating those calculations into neutron irradiation analyses for the RPVs and RVIs must be met.

2 ***Preventive Actions:*** This program is a condition monitoring program through calculation of neutron fluence values and continuous monitoring of their validity; thus, there are no specific preventive actions. Because this program can be used to verify that the inputs and assumptions associated with neutron fluence in the irradiation embrittlement TLAAs (described in SRP-SLR Section 4.2) remain within their respective limits, this program can prevent those TLAAs from being outside of the acceptance criteria that are set as regulatory or design limits in the analyses. Because the program is used to determine that the inputs and assumptions associated with neutron fluence in irradiation embrittlement TLAAs will remain within their respective limits, this program does have some preventative aspects to it.

3 ***Parameters Monitored or Inspected:*** This program monitors component neutron fluence, as determined by the neutron fluence analyses, and appropriate plant and core operating parameters that affect the calculated neutron fluence. The calculational methods, benchmarking, qualification, and surveillance data are monitored to maintain the adequacy of neutron fluence calculations. Neutron fluence levels in specific components are monitored to verify that component locations within the scope of this program are identified.

Neutron fluence is estimated using a computational method that incorporates the following major elements: (1) determination of the geometrical and material input data for the reactor core, vessel and internals, and cavity; (2) determination of the characteristics of the neutron flux emitting from the core; (3) transport of the neutrons from the core to the vessel and into the cavity; and (4) qualification of the calculational procedure.

Guidance on acceptable methods and assumptions for determining RPV neutron fluence is described in NRC RG 1.190. The use of RG 1.190-adherent methods to estimate neutron fluence for the RPV beltline regions significantly above and below the active fuel region of the core, and for RVI components may require additional justification, even if those methods were approved by the NRC for RPV neutron fluence calculations.

4 ***Detection of Aging Effects:*** The program uses applicant-defined activities or methods to track the RPV and RVI component neutron fluence levels. The neutron fluence levels estimated in this program are used as input to the evaluation for determining applicable aging effects for RPV and RVI components, including evaluation of TLAAs as described in SRP-SLR Section 4.2.

5 ***Monitoring and Trending:*** Monitoring and trending of neutron fluence are needed to ensure the continued adequacy of various neutron fluence analyses as identified as TLAAs for the SLRA. When applied to RVI components and to components significantly above and below the active fuel region of the core, the program also assesses and justifies whether the current neutron fluence methodology for the CLB is acceptable for monitoring and projecting the neutron fluence values for these components during the subsequent period of extended operation, or else appropriately enhances (with justification) the program's monitoring and trending element activities accordingly on an as-needed basis. Trending is performed to ensure that plant and core operating conditions remain consistent with the assumptions used in the neutron fluence analyses and that the analyses are updated as necessary.

Neutron fluence estimates are typically determined using a combination of plant and core operating history data that address past plant operating conditions, and projections that are intended to address future operation. Although projections for future operation may conservatively over-estimate the core neutron flux to cover potential variations in plant and core operation and increases in neutron flux at any given time, there is no explicit requirement to do so. Therefore, projections for future plant and core operation should be periodically verified to ensure that any projections used in the neutron fluence calculations remain bounding with respect to actual plant operating conditions.

This program monitors in-vessel or ex-vessel dosimetry capsules and evaluates the dosimetry data, as needed. Additional in-vessel or ex-vessel dosimetry capsules may be needed when the reactor surveillance program has exhausted the available capsules for in-vessel exposure.

6 ***Acceptance Criteria:*** There are no specified acceptance values for neutron fluence; the acceptance criteria are related to the different parameters that are evaluated using neutron fluence, as described in SRP-SLR Section 4.2.

NRC RG 1.190 provides guidance for acceptable methods to determine neutron fluence for the RPV beltline region. Note, however, that applying RG 1.190-adherent methods to determine neutron fluence in locations other than those close to the active fuel region of the core may require additional justification regarding; for example, the level of detail used to represent the core neutron source, the methods to synthesize the three-dimensional flux field, and the order of angular quadrature used in the neutron transport calculations. The applicability of existing qualification data may also require additional justification.

Several examples of acceptable approaches used to provide the above-suggested justification are available. The NRC staff reviewed additional qualification data in the safety evaluation approving Licensing Topical Report BWRVIP 145NP-A, "BWR Vessel Internals Project, Evaluation of Susquehanna Unit 2 Top Guide and Core Shroud Materials Samples Using RAMA Fluence Methodology." An additional example of an approach that uses more refined nuclear and transport methods than recommended in RG 1.190, instead of additional qualification data, is available on page 3-156 of NUREG–2181, "Safety Evaluation Report Related to the License Renewal of Sequoyah Nuclear Plant Units 1 and 2." These examples supported the qualification of different methods to estimate fluence for RVI components. Another example, specific to subsequent license renewal, is available in the NRC Staff's Safety Evaluation Report (SER) Related to the Subsequent License Renewal of Turkey Point Generating Units 3 and 4. The NRC staff's evaluation of the fluence AMP appears in Section 3.0.3.2.2. Neutron Fluence Monitoring, for RPV beltline regions significantly above and below the active fuel region of the core and RVI components. In addition, on pages 3-72–3-74 of the SER, the staff evaluated plant-specific fluence calculations for RVI components to demonstrate the validity of a more generic fluence estimate for downstream consideration in the aging management of those RVI components. These examples all describe ways in which applicants justified the application of RG 1.190-adherent methods, or appropriate alternatives, to evaluate fluence in regions outside the immediate, core-adjacent area of the RPV beltline.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

a. The program provides for corrective actions by updating the analyses for the RPV components, or assessing the need to revise the augmented inspection bases for RVI components, if the neutron fluence assumptions in RPV analyses or augmented inspection bases for RVI components are projected to be exceeded during the subsequent period of extended operation. Acceptable corrective actions include revisions of the neutron fluence calculations to incorporate additional operating history data, as such data become available; use of improved modeling approaches to obtain more accurate neutron fluence estimates; and rescreening of RPV and RVI components when the estimated neutron fluence exceeds threshold values for specific aging mechanisms.

b. When the fluence monitoring activities are used to confirm the validity of existing RPV neutron irradiation embrittlement analyses and result in the need for an update of an analysis that is required by a specific 10 CFR Part 50 regulation, the corrective actions to be taken follow those prescribed in the applicable regulation.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The program reviews industry and plant operating experience (OE) relevant to neutron fluence. Applicable OE affecting the neutron fluence estimate is to be considered when selecting the components for monitoring. RG 1.190 provides expectations for updating the qualification database for the neutron fluence methods via the OE gathered from RPV material surveillance program data. This operational experience is in accordance with the requirements of 10 CFR Part 50 Appendix H.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR Part 50, Appendix G, "Fracture Toughness Requirements*."* Washington, DC: U.S. Nuclear Regulatory Commission. 2016.

10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements." Washington, DC: U.S. Nuclear Regulatory Commission. 2016.

10 CFR 50.55a, "Codes and Standards." Washington, DC: U.S. Nuclear Regulatory Commission. 2016.

10 CFR 50.60, "Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactor for Normal Operation." Washington, DC: U.S. Nuclear Regulatory Commission. 2016.

10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." Washington, DC: U.S. Nuclear Regulatory Commission. 2016.

10 CFR 50.61a, "Alternate Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." Washington, DC: U.S. Nuclear Regulatory Commission. 2016.

NRC. Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." Agencywide Documents Access and Management System (ADAMS) Accession No. ML010890301. Washington, DC: U.S. Nuclear Regulatory Commission. March 2001. NRC 2001-TN8000

NUREG–2181, "Safety Evaluation Report Related to the License Renewal of Sequoyah Nuclear Plant Units 1 and 2." Dockets 50-327 and 50-328, ADAMS Accession No. ML15187A206. Washington, DC: U.S. Nuclear Regulatory Commission. July 2015. NRC 2015-TN8001

"Safety Evaluation Report Related to the Subsequent License Renewal of Turkey Point Generating Units 3 and 4." Dockets 50-250 and 50-251, ADAMS Accession No. ML19191A057. Washington, DC: U.S. Nuclear Regulatory Commission. December 2019. NRC 2019-TN8002

Watkins, K.E., "BWR Vessel Internals Project, Evaluation of Susquehanna Unit 2 Top Guide and Core Shroud Materials Samples Using RAMA Fluence Methodology," BWRVIP-145-NP-A, ADAMS Accession No. ML100260948. Palo Alto, CA: Electric Power Research Institute. October 2009. EPRI 2009-TN8003

X.S STRUCTURAL

X.S1 CONCRETE CONTAINMENT UNBONDED TENDON PRESTRESS

Program Description

This time-limited aging analysis (TLAA) aging management program (AMP) provides reasonable assurance of the adequacy of prestressing forces in unbonded tendons of prestressed concrete containments, during the subsequent period of extended operation, under Title 10 of the *Code of Federal Regulations* (10 CFR) 54.21(c)(1)(iii)(TN4878). The program consists of an assessment of measured tendon prestress forces from required examinations performed in accordance with Subsection IWL of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, as incorporated by reference in 10 CFR 50.55a (TN249), and as further supplemented herein. The assessment related to the adequacy of the prestressing force for each tendon group based on type (i.e., hoop, vertical, dome, inverted-U, helical) and other considerations (e.g., geometric dimensions, whether affected by repair/replacement, etc.) establishes (1) acceptance criteria in accordance with ASME Code Section XI, Subsection IWL, and (2) trend lines constructed based on the guidance provided in the U.S. Nuclear Regulatory Commission (NRC) Information Notice (IN) 99-10, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments.” The NRC Regulatory Guide 1.35.1, “Determining Prestressing Forces for Inspection of Prestressed Concrete Containments,” may be used for guidance related to calculation of prestressing losses and predicted forces.

Evaluation and Technical Basis

1 ***Scope of Program:*** The program addresses the assessment of unbonded tendon prestressing forces measured in accordance with ASME Code Section XI, Subsection IWL, when an applicant performs the concrete containment prestressing force TLAA using 10 CFR 54.21(c)(1)(iii).

2 ***Preventive Actions:*** This is primarily a condition monitoring program that periodically measures and evaluates tendon forces such that corrective action can be taken, if required, prior to tendon forces falling below minimum required values established in the design. Maintaining the prestressing above the minimum required value (MRV) (prestressing force), as described under the acceptance criteria below, provides reasonable assurance that the structural and functional adequacy of the concrete containment is maintained.

3 ***Parameters Monitored:*** The parameters monitored are the concrete containment tendon prestressing forces in accordance with ASME Code Section XI, Subsection IWL. The prestressing forces are measured on common (control) tendons and tendons selected by random sampling of each tendon group using the lift-off or equivalent method.

4 ***Detection of Aging Effects:*** The loss of concrete containment tendon prestressing forces is detected by measuring tendon forces, and by analyzing (predicting) tendon forces and trending the data obtained as part of ASME Code Section XI, Subsection IWL examinations.

5 ***Monitoring and Trending:*** In addition to Subsection IWL examination requirements, the estimated and all measured prestressing forces up to the current examination are plotted against time. The predicted lower limit (PLL) line, MRV, and trend line are developed for each tendon group examined for the subsequent period of extended operation. The trend line represents the general variation of prestressing forces with time based on the actual measured forces in individual tendons of the specific tendon group. The trend line for each tendon group is constructed by regression analysis of all measured prestressing forces in individual tendons of that group obtained from all previous examinations. The PLL line, MRV, and trend line for each tendon group are projected to the end of the subsequent period of extended operation. The trend lines are updated at each scheduled examination.

6 ***Acceptance Criteria:*** The prestressing force trend line (constructed as indicated under the Monitoring and Trending program element) for each tendon group must indicate that existing prestressing forces in the concrete containment tendon would not fall below the appropriate MRV prior to the next scheduled examination. If the trend line crosses the PLL line, its cause should be determined, evaluated, and corrected. The trend line crossing the PLL line is an indication that the existing prestressing forces in concrete containment could fall below the MRV. Any indication in the trend line that the overall prestressing force in any tendon group(s) could potentially fall below the MRV during the subsequent period of extended operation is evaluated, the cause(s) is/are documented, and corrective action(s) is/are performed in a timely manner.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

If acceptance criteria are not met then either systematic retensioning of tendons or a reanalysis of the concrete containment is warranted so that the design adequacy of the containment is demonstrated.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The program incorporates a review of the relevant operating experience (OE) that has occurred at the applicant's plant as well as at other plants. NUREG/CR–7111, "A Summary of Aging Effects and their Management in Reactor Spent Fuel Pools, Refueling Cavities, Tori, and Safety-Related Concrete Structures," summarizes observations of low prestress forces recorded in some plants. However, tendon OE may vary at different plants that have prestressed concrete containments. The difference could be due to the prestressing system design (e.g., button-headed, wedge, or swaged anchorages), environment, and type of reactor (i.e., pressurized water reactor and boiling water reactor) and possible concrete containment modifications. Thus, the applicant's plant-specific OE is reviewed and evaluated in detail for the subsequent period of extended operation. Applicable portions of the experience with prestressing systems described in NRC IN 99-10 could be useful.

If plant-specific OE indicates degradation and/or losses that may fall below minimum required values established in the design, additional examinations may be required to determine the condition of an expanded tendon group. Upward trending group prestress forces or tendon measurements shall be further assessed as part of the OE.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

Table X-01. FSAR Supplement Summaries for GALL-SLR Report Chapter X Aging Management Programs That May Be Used to Demonstrate the Acceptability of Time-Limited Aging Analyses in Accordance with 10 CFR 54.21(c)(1)(iii)

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule[(a)]
X.M1	Fatigue Monitoring	This program is used to accept fatigue or other types of cyclical loading time-limited aging analyses (TLAAs) in accordance with the acceptance criterion in 10 CFR 54.21(c)(1)(iii) (TN4878). The aging management program monitors and tracks the number of occurrences and severity of design basis transients assessed in the applicable fatigue or cyclical loading analyses, including those in applicable cumulative usage factor (CUF) analyses, environmentally adjusted cumulative usage factor (CUF_{en}) analyses, maximum allowable stress range reduction/expansion stress analyses for American National Standards Institute (ANSI) B31.1 and American Society of Mechanical Engineers (ASME) Code Class 2 and 3 components, ASME III fatigue waiver analyses, and cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses. The program also monitors applicable design transient parameters (e.g., temperatures, pressures, displacements, strains, flow rates, etc.) for components with stress-based fatigue calculations. The program manages cumulative fatigue damage or cracking induced by fatigue or cyclic loading in the applicable structures and components through performance of activities that monitor one or more relevant analysis parameters, such as CUF values, CUF_{en} values, design transient cycle limit values, predicted flaw size values, or plant-specific parameter values used in stress-based fatigue analysis methodologies. The program also sets applicable acceptance criteria (limits) on these parameters. Therefore, the program has two aspects, one to verify the continued acceptability of existing analyses through cycle counting or	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule[a]
		parameter monitoring and the other to provide periodically updated evaluations of the analyses to demonstrate that they continue to meet the appropriate limits. The program also implements appropriate corrective actions (e.g., reanalysis, component or structure inspections, or component or structure repair or replacement activities) when acceptance limits are approached. Plant technical specification requirements may apply to the scope of this program.	
X.M2	Neutron Fluence Monitoring	This program monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor pressure vessel and reactor internal components to ensure that applicable reactor pressure vessel neutron irradiation embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessment for reactor internal components will remain within their applicable limits. This program has two aspects, one to verify the continued acceptability of existing analyses through neutron fluence monitoring and the other to provide periodically updated evaluations of the analyses involving neutron fluence inputs to demonstrate that they continue to meet the appropriate limits defined in the current licensing basis (CLB). Monitoring is performed to verify the adequacy of neutron fluence projections, which are defined for the CLB in reports approved by the U.S. Nuclear Regulatory Commission (NRC). For fluence monitoring activities that apply to the beltline region of the reactor pressure vessel(s), the calculational methods are generally performed in a manner that is consistent with Regulatory Guide (RG) 1.190 (TN8000), “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” March 2001. Additional justifications may be necessary for neutron fluence monitoring, regarding methods that are applied to reactor pressure vessel locations outside of the beltline region of the vessels or to reactor internal components. This program’s results are compared to the neutron fluence parameter inputs used in the neutron	The program is implemented 6 months prior to the subsequent period of extended operation.

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule[(a)]
		embrittlement analyses for reactor pressure vessel components. This includes but is not limited to the neutron fluence inputs for the reactor pressure vessel upper shelf energy analyses (or equivalent margin analyses, as applicable to the CLB), pressure-temperature limits analyses, and low temperature overpressure protection (LTOP, pressurized water reactors [PWRs] only) that are required to be performed in accordance with 10 CFR Part 50 (TN249), Appendix G requirements, and for PWRs, those safety analyses that are performed to demonstrate adequate protection of the reactor pressure vessels against the consequences of pressurized thermal shock (PTS) events, as required by 10 CFR 50.61 or 10 CFR 50.61a and applicable to the CLB. Comparisons to the neutron fluence inputs for other analyses (as applicable to the CLB) may include those for mean reference nil-ductility temperature (RT_{NDT}) and probability of failure analyses for boiling water reactor (BWR) reactor pressure vessel circumferential and axial shell welds, BWR core reflood design analyses, and aging effect assessments for PWR and BWR reactor internals that are induced by neutron irradiation exposure mechanisms. Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the applicant's Reactor Vessel Surveillance Program (Refer to Generic Aging Lessons Learned for Subsequent License Renewal [GALL-SLR] Report AMP XI.M31) may provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant technical specifications or in specific regulations of 10 CFR Part 50 may apply, including those in 10 CFR Part 50, Appendix G; 10 CFR 50.55a; and for PWRs, the PTS requirements in 10 CFR 50.61 or 10 CFR 50.61a, as applicable for the CLB.	
X.S1	Concrete Containment Tendon Prestress	This program monitors and assesses the adequacy of the prestressing force for each tendon group based on type (i.e., hoop, vertical, dome, inverted-U, helical) and other considerations (e.g., geometric dimensions, whether affected by repair/replacement, etc.). The program ensures, during each inspection, that the trend lines of the measured prestressing	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule[a]
		forces remain above the minimum required value before the next scheduled inspections occur. Otherwise, corrective actions are taken to ensure containment prestress adequacy. Acceptance criteria follow 10 CFR 50.55a, ASME Code Section XI (Subsection IWL) and include construction of trend lines consistent with NRC Information Notice (IN) 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments." The NRC RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments," provides guidance for calculating prestressing losses and predicted forces. The program incorporates plant-specific and industry operating experience.	period of extended operation.
X.E1	Environmental Qualification (EQ) of Electric Components	This program implements the EQ requirements in 10 CFR Part 50 (TN249), Appendix A, Criterion 4, and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform their safety functions in those harsh environments after the effects of inservice aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ. As required by 10 CFR 50.49, EQ equipment not qualified for the current license term is refurbished, replaced, or has its qualification extended prior to reaching the designated life aging limits established in the evaluation. Aging evaluations for EQ equipment that specify a qualification of at least 60 years are TLAAs for SLR. This program is implemented in accordance 10 CFR 50.49 and 10 CFR 54.21(c)(1)(iii). Along with GALL-SLR Report AMP X.E1 the EQ program demonstrates the acceptability of the TLAA analysis under 10 CFR 54.21(c)(1) and is considered an AMP for the subsequent period of extended operation.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP = aging management program; ANSI = American National Standards Institute; ASME = American Society of Mechanical Engineers; BWR = boiling water reactor; CFR = Code of Federal Regulations; CLG = current licensing basis; CUF = cumulative usage factor; CUF_{en} = environmentally adjusted cumulative usage factor; EQ = environmental qualification; GALL-SLR = Generic Aging Lessons Learned for Subsequent License Renewal; LTOP = low temperature overpressure protection; NRC = U.S. Nuclear Regulatory Commission; PWR = pressurized water reactor; RG = Regulatory Guide; TLAA = time-limited aging analysis.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 54.21, “Contents of Application-Technical Information.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 54-TN4878

ASME. ASME Code Section XI, Subsection IWL, “Requirements for Class CC Concrete Components of Light-Water Cooled Plants.” New York, New York: American Society of Mechanical Engineers. 2008.

NRC. Information Notice 99-10, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML031500244. Washington, DC: U.S. Nuclear Regulatory Commission. April 1999.

_____. NUREG/CR–7111, “A Summary of Aging Effects and their Management in Reactor Spent Fuel Pools, Refueling Cavities, Tori, and Safety-Related Concrete Structures.” ADAMS Accession No. ML12047A184. Washington, DC: U.S. Nuclear Regulatory Commission. January 2012.

_____. Regulatory Guide 1.35.1, “Determining Prestressing Forces for Inspection of Prestressed Concrete Containments.” ADAMS Accession No. ML003740040. Washington, DC: U.S. Nuclear Regulatory Commission. July 1990.

CHAPTER XI

AGING MANAGEMENT PROGRAMS

XI AGING MANAGEMENT PROGRAMS

XI.M9	BWR VESSEL INTERNALS
XI.M10	BORIC ACID CORROSION
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)
XI.M12	THERMAL AGING EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL ~~(CASS)~~
XI.M16	PWR VESSEL INTERNALS
	M16A PWR VESSEL INTERNALS
XI.M17	FLOW-ACCELERATED CORROSION
XI.M18	BOLTING INTEGRITY
XI.M19	STEAM GENERATORS
XI.M20	OPEN-CYCLE COOLING WATER SYSTEM
XI.M21A	CLOSED TREATED WATER SYSTEMS
XI.M22	BORAFLEX MONITORING
XI.M23	INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS
XI.M24	COMPRESSED AIR MONITORING
XI.M25	BWR REACTOR WATER CLEANUP SYSTEM
XI.M26	FIRE PROTECTION
XI.M27	FIRE WATER SYSTEM
XI.M29	OUTDOOR AND LARGE ATMOSPHERIC METALLIC STORAGE TANKS
XI.M30	FUEL OIL CHEMISTRY
XI.M31	REACTOR VESSEL MATERIAL SURVEILLANCE
XI.M32	ONE-TIME INSPECTION
XI.M33	SELECTIVE LEACHING
XI.M35	ASME CODE CLASS 1 SMALL-BORE PIPING
XI.M36	EXTERNAL SURFACES MONITORING OF MECHANICAL COMPONENTS

XI.E ELECTRICAL

XI.E1 ELECTRICAL INSULATION FOR ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

The purpose of this aging management program (AMP) is to provide reasonable assurance that the intended functions of electrical cable insulating material (e.g., power, control, and instrumentation) and connection insulating material that are not subject to the environmental qualification (EQ) requirements of Title 10 of the *Code of Federal Regulations* (10 CFR) 50.49 (TN249) are maintained consistent with the current licensing basis through the subsequent period of extended operation.

In most areas within a nuclear power plant, the actual operating environment (e.g., temperature, radiation, or moisture) is less severe than the plant design basis environment. However, in a limited number of localized areas, the actual environment may be more severe than the anticipated plant design basis environment. These localized areas are characterized as "adverse localized environments" that represent a limited plant area in which the operating environment is significantly more severe than the plant design environment.

An adverse localized environment is an environment that exceeds the most limiting environment (e.g., temperature, radiation, or moisture) for the electrical insulation of cables that are coated with fire-retardant material and connectors. Electrical insulation used in electrical cables and connections may degrade more rapidly than expected when exposed to an adverse localized environment. Cable or connection electrical insulation subjected to an adverse localized environment may increase the aging rate of a component or have an adverse effect on its operability.

Adverse localized environments are identified through the use of an integrated approach. The approach includes, but is not limited to (1) the review of EQ program radiation levels, temperatures, and moisture levels; (2) recorded information from equipment or plant instrumentation; (3) as-built and field walkdown data (e.g., cable routing data base); (4) a plant spaces scoping and screening methodology; and (5) the review of relevant plant-specific and industry operating experience (OE). This OE includes, but is not limited to the following:

- identification of work practices that have the potential to subject in-scope cable and connection electrical insulation to an adverse localized environment (e.g., equipment thermal insulation removal and restoration);
- corrective actions involving in-scope electrical cable and connection electrical insulation material service life (current operating term);
- previous walkdowns including visual inspection of accessible cable and connection electrical insulation; and
- environmental monitoring (e.g., long-term periodic environmental monitoring–temperature, radiation, or moisture).

Periodic environmental monitoring consists of a representative number of environmental measurements taken over a sufficient period of time and periodically evaluated to establish the environment for condition monitoring electrical insulation. Plant environmental data can be used in an aging evaluation in different ways, such as by directly applying the plant data in the evaluation or using the plant data to demonstrate conservatism. The methodology employed for monitoring, data collection, and the analysis of localized component environmental data (including temperature, radiation, and moisture) is documented in the record of the analysis. Documentation is provided, as needed, of the applicability of methodologies using data that are collected and evaluated once, or are of limited duration.

Accessible in-scope cables and connections are visually inspected for degradation. Visual inspection findings may necessitate testing. Testing comprises one or more tests using mechanical, electrical, or chemical means implemented on a sampling basis and represents, with reasonable assurance, both accessible and inaccessible in-scope cable and connection electrical insulation degradation.

Accessible in-scope cable and connection inspection is considered a visual inspection performed from the floor, with the use of scaffolding as available, without the opening of junction boxes, pull boxes, or terminal boxes. The purpose of the visual inspection is to identify adverse localized environments (employing diagnostic tools such as thermography as applicable). These potential adverse localized environments are then evaluated, which may require further inspection using scaffolding or other means (e.g., opening of junction boxes, pull boxes, accessible pull points, panels, terminal boxes, and junction boxes) to assess cable and connector electrical insulation aging degradation.

The cable condition monitoring portion of the AMP uses component sampling for cable and connection electrical insulation testing, if deemed necessary. The following factors are considered in the development of the electrical insulation sample: the environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location (high temperature, high humidity, vibration, etc.), and the electrical insulation composition. The component sampling methodology uses a population that includes a representative sample of in-scope electrical cable and connection types regardless of whether the component was included in a previous aging management or maintenance program. The technical basis for the sample selection is documented.

Electrical insulation material for cables and connections previously identified and dispositioned during the first period of extended operation as subjected to an adverse localized environment are evaluated for cumulative aging effects during the subsequent period of extended operation. If an unacceptable condition or situation is identified for cable or connection electrical insulation by visual inspection or test, corrective actions are taken including making a determination about whether the same condition or situation is applicable to other in-scope accessible and inaccessible cable or connection electrical insulation (e.g., extent of condition). As such, this program does not apply to plants in which most cables are inaccessible.

As stated in NUREG/CR–5643, “the major concern is that failures of deteriorated cable systems (cables, connection electrical insulation) might be induced during accident conditions.” Because the cable and connection electrical insulation is not subject to the EQ requirements of 10 CFR 50.49 (TN249), an AMP is needed to manage the aging mechanisms and effects for the subsequent period of extended operation. The AMP provides reasonable assurance that the insulation for electrical cables and connections will perform its intended function for the subsequent period of extended operation.

Evaluation and Technical Basis

1 ***Scope of Program:*** This AMP applies to accessible cable and connection electrical insulation within the scope of subsequent license renewal, including in-scope cables and connections subjected to an adverse localized environment.

2 ***Preventive Actions:*** This is a condition monitoring program and no actions are taken as part of this program to prevent or mitigate aging degradation.

3 ***Parameters Monitored or Inspected:*** Accessible in-scope cable and connection electrical insulation subject to an adverse localized environment is visually inspected for surface anomalies. The cable insulation visual inspection portion of the AMP considers the aging effects experienced by cable or connection jacket material to be representative of the aging effects experienced by the cable and connection electrical insulation. Cable and connection electrical insulation material are evaluated for signs of reduced electrical insulation resistance due to an adverse localized environment of temperature, moisture, radiation, and oxygen that includes radiolysis, photolysis (ultraviolet sensitive materials only) of organics, radiation-induced oxidation, and moisture intrusion, indicated by signs of electrical insulation embrittlement, discoloration, cracking, melting, swelling, or surface contamination.

An adverse localized environment is a plant-specific condition; therefore, the applicant should clearly define the most limiting temperature, radiation, and moisture environments and their basis. For the subsequent period of extended operation, the applicant reviews plant-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation (i.e., service life). The applicant should also inspect for adverse localized environments for each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, moisture, or contamination).

4 ***Detection of Aging Effects:*** Aging effects resulting from temperature, radiation, or moisture cause surface abnormalities in the cable jacket and connection material. Accessible electrical cables and connections are visually inspected for cable jacket and connection electrical insulation surface anomalies such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination. Cables and electrical connections are inspected to identify cable and connection insulation coated with fire-retardant material installed in an adverse localized environment. Plant-specific OE is also evaluated to identify in-scope cable and connection insulation previously subjected to adverse localized environments during the period of extended operation. Cable and connection insulation is evaluated to confirm that the dispositioned corrective actions continue to support the in-scope cable and connection during the subsequent period of extended operation.

The inspection of accessible cable and connection insulation material is used to evaluate the adequacy of inaccessible cable and connection electrical insulation. Accessible electrical cables and connections subjected to an adverse localized environment found in the performance of this AMP are visually inspected at least once every 10 years. This is an adequate period to preclude failures of the cables and connection electrical insulation because experience has shown that aging degradation is a slow process. If visual inspections identify degraded or damaged conditions, as defined in Element 3 of this AMP, then testing may be performed for evaluation. For a large number of cables and connections identified as being potentially degraded, a sample population is tested. The first inspection for subsequent license renewal is to be completed prior to the subsequent period of extended operation. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration, or surveillance program may be credited in lieu of testing recommended in this AMP.

This AMP, as noted, is a cable and connection electrical insulation condition monitoring program that uses sampling. A sample of 20 percent of each cable and connection type with a maximum sample size of 25 is tested. The following factors are considered in the development of the cable and connection insulation test sample: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location (high temperature, high humidity, vibration, etc.), and insulation material. The component sampling methodology uses a population that includes a representative sample of in-scope electrical cable and connection types regardless of whether the component was included in a previous aging management or maintenance program. The technical basis for the sample selection is documented.

5 ***Monitoring and Trending:*** Trending actions are not included as part of this AMP, because the ability to trend visual inspection and test results is dependent on the test or visual inspection program selected. However, condition monitoring of cable and connection insulation using visual inspection and test results that are trendable provide additional information about the rate of cable or connection insulation degradation.

6 ***Acceptance Criteria:*** Electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in the applicant's procedures. Visual inspection results show that accessible cable and connection insulation material are free from unacceptable signs of surface abnormalities that indicate unusual cable or connection insulation aging effects exist. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of the intended function.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Unacceptable test results and visual indications of cable and connection electrical insulation abnormalities are subject to an engineering evaluation. Such an evaluation considers the age and operating environment of the component, as well as the severity of the abnormality and whether such an abnormality has previously been correlated to degradation of cable or connection insulation. Corrective actions include, but are not limited to, testing, shielding, or otherwise mitigating the environment or relocation or replacement of the affected cables or connections. When an unacceptable condition or situation is identified, a determination is made about whether the same condition or situation is applicable to additional in-scope accessible and inaccessible cables or connections (extent of condition).

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Industry OE has identified cable and connection insulation aging effects due to adverse localized environments caused by elevated temperature, radiation, or moisture. For example, cable and connection insulation located near steam generators, pressurizers, or areas that may be subjected to an adverse localized environment. These environments have been found to cause degradation of electrical cable and connection electrical insulation that are visually observable, such as color changes or surface abnormalities. These visual indications along with cable condition monitoring can be used as indicators of cable and connection insulation degradation.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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XI.E2 ELECTRICAL INSULATION FOR ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS

Program Description

The purpose of this aging management program (AMP) is to provide reasonable assurance that the intended functions of electrical cables and connections (that are not subject to the environmental qualification requirements of Title 10 of the *Code of Federal Regulations* (10 CFR) 50.49 (TN249) and are used in instrumentation circuits that have sensitive, high voltage, low-level current signals are maintained consistent with the current licensing basis through the subsequent period of extended operation.

In most areas within a nuclear power plant the actual operating environment (e.g., temperature, radiation, or moisture) is less severe than the plant design bases environment. However, in a limited number of localized areas, the actual environment may be more severe than the plant design bases environment. These localized areas are characterized as “adverse localized environments” that represent a limited plant area in which the operating environment is significantly more severe than the plant design basis environment. An adverse localized environment exceeds the most limiting environment (e.g., temperature, radiation, or moisture) for the cable or connection insulation. A discussion of adverse localized environments and methods of identifying them can be found in Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.E1.

Exposure of electrical insulation to adverse localized environments caused by temperature, radiation, or moisture can cause age degradation resulting in reduced electrical insulation resistance, moisture intrusion-related connection failures, or errors induced by thermal transients. Reduced electrical insulation resistance causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in electrical insulation resistance is a concern for all circuits, but especially those that have sensitive, high-voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation circuits, because a reduced insulation resistance may contribute to signal inaccuracies.

In this AMP, in addition to the evaluation and identification of adverse localized environments, either of two methods can be used to identify the existence of electrical insulation aging effects for cables and connections. In the first method, calibration results or findings of surveillance testing programs are evaluated to identify the existence of electrical cable and connection insulation aging degradation. In the second method, direct testing of the cable system is performed.

This AMP applies to high-range-radiation and neutron flux monitoring instrumentation cables in addition to other cables used in high-voltage, low-level current signal applications that are sensitive to reduction in electrical insulation resistance. For these cables, GALL-SLR Report AMP XI.E1 does not apply.

As stated in NUREG/CR–5643, “the major concern is that failures of deteriorated cables might be induced during accident conditions.” Because the cable and connection electrical insulation is not subject to the environmental qualification requirements of 10 CFR 50.49, an AMP is needed to manage the aging mechanisms and effects for the subsequent period of extended operation. This AMP provides reasonable assurance that the electrical insulation for electrical cables and connections will perform its intended function for the subsequent period of extended operation.

Evaluation and Technical Basis

1. ***Scope of Program:*** This AMP applies to the electrical insulation applied to electrical cables and connections (cable system) used in circuits that have sensitive, high-voltage, low-level current signals. Examples of these circuits include radiation monitoring and nuclear instrumentation that is subject to aging management review and subjected to adverse localized environments caused by temperature, radiation, or moisture.

2. ***Preventive Actions:*** This is a performance monitoring program and no actions are taken as part of this program to prevent or mitigate aging degradation.

3. ***Parameters Monitored or Inspected:*** The parameters monitored are determined from the specific calibration, surveillances, or testing performed and are based on the specific instrumentation circuit under surveillance or calibration, as documented in plant procedures.

4. ***Detection of Aging Effects:*** Review of calibration results or findings of surveillance programs can provide an indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. By reviewing the results obtained during normal calibration or surveillance, an applicant may detect severe aging degradation prior to the loss of the intended function of the cable and connection. The first reviews are completed prior to the subsequent period of extended operation and at least every 10 years thereafter. Calibration or surveillance results that do not meet the acceptance criteria are reviewed for aging effects when the results are available.

   Cable system testing is conducted when the calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results described above. A cable system test for detecting deterioration of the electrical insulation system is performed. This can be one or more of the following tests: insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation physical, mechanical, and chemical properties, as applicable. The test frequency of the cable system is determined by the applicant based on engineering evaluation, but the test frequency is at least once every 10 years. The first test is to be completed prior to the subsequent period of extended operation.

5. ***Monitoring and Trending:*** Trending actions are not included as part of this AMP, because the ability to trend visual inspection and test results is dependent on the test or visual inspection program selected. However, inspection and test results that are trendable provide additional information about the rate of cable or connection degradation.

6. ***Acceptance Criteria:*** An unacceptable indication is defined as a noted condition or situation, if left unmanaged, could potentially lead to a loss of intended function.

   Calibration results or findings of surveillance and cable system testing are to be within the acceptance criteria, as set out in the applicant's procedures.

7. ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this

AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Corrective actions, such as recalibration and circuit trouble-shooting, are implemented when calibration, surveillance, or cable system test results do not meet the acceptance criteria. An engineering evaluation is performed when the acceptance criteria are not met. Such an evaluation is to consider the significance of the calibration, surveillance, or cable system test results and whether the review of calibration and surveillance results or the cable system testing frequency needs to be increased.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** OE has identified that a change in temperature across a high-range radiation monitor cable in containment resulted in a substantial change in the reading of the monitor. Changes in instrument calibration can be caused by degradation of the circuit cable or connection electrical insulation and represents a possible indication of electrical cable degradation.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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XI.E3

XI.E3A ELECTRICAL INSULATION FOR INACCESSIBLE MEDIUM-VOLTAGE POWER CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

The purpose of this aging management program (AMP) is to provide reasonable assurance that the intended functions of inaccessible medium-voltage power cables (operating voltages of 2 kV to 35 kV) that are not subject to the environmental qualification requirements of Title 10 of the *Code of Federal Regulations* (10 CFR) 50.49 (TN249) are maintained consistent with the current licensing basis through the subsequent period of extended operation. This AMP applies to all inaccessible or underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) medium-voltage cables that are within the scope of subsequent license renewal (SLR) and are potentially exposed to wetting or submergence (i.e., significant moisture). Inaccessible medium-voltage cables designed for continuous wetting or submergence are also included in this AMP for a one-time inspection and test.

Most electrical cables in nuclear power plants are located in dry environments. However, some cables are inaccessible or underground, located in buried conduits, cable trenches, cable troughs, duct banks, vaults, or direct buried installations that may be exposed to water intrusion due to wetting or submergence. When an inaccessible medium-voltage power cable is exposed to wet, submerged, or other environments for which it was not designed, age-related degradation of the electrical insulation may occur. Electrical insulation subjected to wetting or submergence could have an adverse effect on operability, or potentially lead to failure of the cable insulation system. Although variations exist in the aging mechanisms and effects depending on cable insulation material and manufacture, periodic actions are necessary to minimize the potential for insulation degradation.

Periodic actions are taken to prevent inaccessible medium-voltage cables from being exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than 3 days (i.e., long-term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for this AMP.

The inspection frequency for water accumulation is established and performed based on plant-specific operating experience (OE) with cable wetting or submergence over time. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually, and the first inspection for SLR is completed prior to the subsequent period of extended operation. Inspection frequencies are adjusted based on inspection results including plant-specific OE but with a minimum inspection frequency of at least once annually. Inspections are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pumpout of accumulated water prior to the wetting or submergence of cables can be performed at least once every 5 years, if supported by plant OE. Inspections of manholes equipped with water level monitoring and alarms are also performed after event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent level alarm). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or in the control room. The reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

Examples of periodic actions to mitigate inaccessible medium-voltage cable exposure to significant moisture include inspection for water accumulation in cable manholes and conduits and removing water, as needed. However, these actions may not be sufficient to verify that water is not trapped elsewhere in the raceways. For example, water accumulation and submergence could occur as a result of (1) a duct bank conduit with low points in the routing, (2) concrete cracking due to soil settling over a long period of time, (3) manhole covers not being watertight, (4) routing locations subject to a high water table (e.g., high seasonal cycles), and (5) wetting and submergence potential even when duct banks are sloped with the intention to minimize water accumulation.

Therefore, in addition to the above periodic actions, in-scope inaccessible medium-voltage power cables exposed to significant moisture are tested to determine the condition of the electrical insulation. One or more tests may be required based on cable application, construction, and electrical insulation material to determine the age-related degradation of the cable. Cable testing as part of an existing maintenance or surveillance program, with justification, can be credited in lieu of, or in combination with, the testing recommended in this AMP. A plant-specific inaccessible medium-voltage cable test matrix that documents inspection methods, test methods, and acceptance criteria for the applicant's plant-specific in-scope inaccessible medium-voltage power cables is developed based on OE.

Note: Inaccessible medium-voltage cables designed for continuous wetting or submergence are also included in this AMP for a one-time inspection and test with additional periodic tests and inspections determined by the test/inspection results and industry and plant-specific OE.

The first tests for license renewal are to be completed prior to the subsequent period of extended operation with subsequent tests performed at least once every 6 years thereafter. For inaccessible medium-voltage power cables exposed to significant moisture, test frequencies are adjusted based on test results (including trending of aging degradation where applicable) and plant-specific OE but with a minimum test frequency of at least once every 6 years.

As stated in NUREG/CR–5643, "the major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions." Because the cables are not subject to the environmental qualification requirements of 10 CFR 50.49 (TN249), an AMP is required to manage the aging effects. This AMP provides reasonable assurance the insulation material for electrical cables will perform its intended function for the subsequent period of extended operation.

Evaluation and Technical Basis

1 ***Scope of Program:*** This AMP applies to inaccessible or underground medium-voltage (2k V to 35 kV) power cable installations (e.g., direct buried, buried conduit, duct bank, embedded raceway, cable trench, vaults, or manholes) that are within the scope of SLR and are potentially exposed to significant moisture.

Significant moisture is defined as exposure to moisture that lasts more than 3 days that, if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for this AMP.

In-scope inaccessible medium-voltage cable splices subjected to wetting or submergence are also included within the scope of this program. Submarine or other cables designed for continuous wetting or submergence are also included in this AMP as a one-time inspection and test with additional periodic tests and inspections determined by the one-time test/inspection results as well as industry and plant-specific OE.

2 ***Preventive Actions:*** This is a condition monitoring program. However, periodic actions are taken to prevent inaccessible medium-voltage power cables from being exposed to significant moisture, such as identifying and inspecting conduit ends and cable manholes/vaults for water accumulation, and removing the water, as needed.

The inspection frequency for water accumulation is established and performed based on plant-specific OE with cable wetting or submergence. The inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually, and the first inspection for SLR is completed prior to the subsequent period of extended operation. The annual inspection frequency is consistent with U.S. Nuclear Regulatory Commission Inspection Manual, Attachment 71111.06, “Flood Protection Measures.” Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pumpout of accumulated water prior to the wetting or submergence of cables can be performed at least once every 5 years, if supported by plant OE. Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. The reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

Inspections for water accumulation are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. Inspections of manholes equipped with water level monitoring and alarms are performed after event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Plant-specific parameters are established for the initiation of an event-driven inspection. Inspections include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact. Dewatering systems (e.g., sump pumps and passive drains) and associated alarms are inspected and their operation verified periodically. The periodic inspection includes documentation that either automatic or passive drainage systems or manual pumping is effective in preventing cable exposure to significant moisture.

If water is found during inspection, corrective actions are taken per the applicant’s corrective action program to keep the cables free from significant moisture and to assess cable degradation. The aging management of the physical structures, including cable support structures of cable vaults/manholes is managed by Generic Aging Lessons Learned Subsequent License Renewal (GALL-SLR) Report AMP XI.S6, “Structures Monitoring.”

3 ***Parameters Monitored or Inspected:*** Inspection for water accumulation is performed based on plant-specific OE with water accumulation over time.

Inaccessible or underground medium-voltage power cables within the scope of license renewal exposed to significant moisture are tested to determine the age-related degradation of the electrical insulation.

The reliability, self-monitoring features, and operation of continuous water level and alarm capabilities of such devices, if installed and credited for 5-year inspection intervals, are demonstrated routinely depending on the attributes of the specific equipment used.

4 ***Detection of Aging Effects:*** For inaccessible medium-voltage power cables exposed to significant moisture, test frequencies are adjusted based on test results (including the trending of aging degradation where applicable) and plant-specific OE. Cable testing occurs at least once every 6 years. The first tests for license renewal are to be completed prior to the subsequent period of extended operation with additional tests performed at least once every 6 years thereafter. This is an adequate period during which to monitor the performance of the cable and take appropriate corrective actions because experience has shown that although it is a slow process, aging degradation could be significant.

The specific type of test performed is determined prior to the initial test. Testing of installed inservice cables comprises of one or more tests using mechanical, electrical, or chemical means that determines, with reasonable assurance, in-scope inaccessible medium-voltage electrical insulation age-related degradation. One or more tests may be required due to cable application, construction, and electrical insulation material to determine the age-related degradation of the cables. Cable testing as part of an existing maintenance or surveillance program, with justification, can be credited in lieu of, or in combination with, testing recommended in this AMP. A plant-specific inaccessible medium-voltage cable test matrix that documents inspection methods, test methods, and acceptance criteria for the applicant’s in-scope inaccessible medium-voltage power cables is developed based on OE.

5 ***Monitoring and Trending:*** Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components’ intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. However, condition monitoring cable test and inspection results, using the same visual inspection and test methods that are trendable and repeatable, provide additional information about the rate of cable or connection insulation degradation.

6 ***Acceptance Criteria:*** An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of intended function.

The acceptance criteria for each test or inspection are determined by the specific type of test performed and the specific cable tested. Acceptance criteria for inspections for water accumulation are defined by the direct indication that cable support structures are intact and cables are not subject to significant moisture. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected and their operation is verified to prevent unacceptable exposure to significant moisture. Proper and reliable operation, as well as the self-monitoring features of continuous water level and alarm capabilities of such devices, if installed and credited for 5-year inspection intervals, are demonstrated routinely to be functional according to the requirements and attributes of the specific equipment used.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** OE has shown that medium-voltage power cable electrical insulation materials undergo increased degradation either through water tree formation or other aging mechanisms when subjected to significant moisture. Inaccessible medium-voltage cables subjected to significant moisture may result in an increased age-related degradation of electrical insulation. Minimizing exposure to significant moisture mitigates the potential for age-related degradation.

The program is informed and enhanced when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

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XI.E3B ELECTRICAL INSULATION FOR INACCESSIBLE INSTRUMENT AND CONTROL CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

The purpose of this aging management program (AMP) is to provide reasonable assurance that the intended functions of inaccessible or underground instrument and control cables that are not subject to the environmental qualification (EQ) requirements of Title 10 of the *Code of Federal Regulations* (10 CFR) 50.49 (TN249) are maintained consistent with the current licensing basis through the subsequent period of extended operation.

This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) instrumentation and control cables, including those designed for continuous wetting or submergence within the scope of subsequent license renewal (SLR), that are potentially exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than 3 days that, if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

When an inaccessible instrument and control cable is exposed to wet, submerged, or other environments for which it was not designed, accelerated age-related degradation of the electrical insulation may occur. The degradation of the cable shield due to water intrusion may introduce electrical ground issues and noise into the circuit.

The risk contribution due to a failure of an inaccessible instrument and control cable may be limited due to system architecture. However, a common environmental aging stressor, such as submergence, represents an aging mechanism that if not anticipated in the design or mitigated in service, could have an adverse effect on the performance of intended functions, or potentially lead to failure of the cable insulation system.

In this AMP, periodic actions are taken to prevent inaccessible instrumentation and control cables from being exposed to significant moisture.

Examples of periodic actions include inspecting for water accumulation in cable manholes, vaults, conduits, and removing water, as needed. Instrumentation and control cables accessible from manholes, vaults, or other underground raceways are visually inspected for cable surface abnormalities. However, these periodic actions may not be sufficient due to the inability to remove accumulated water trapped in the raceways. For example, water accumulation or submergence could occur as a result of (1) a duct bank conduit with low points in the routing, (2) raceway settling or cracking due to soil settling over a long period of time, (3) manholes and cable trench covers not being watertight, (4) raceway locations subject to a high water table (e.g., high seasonal cycles), and (5) potential wetting or submergence even when duct banks are sloped with the intention to minimize water accumulation.

Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pumpout of accumulated water prior to the wetting or submergence of cables can be performed at least once every 5 years, if supported by plant operating experience (OE). Inspections of manholes equipped with water level monitoring and alarms are also performed after event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent level alarm). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or in the control room. The reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

Therefore, in addition to the above periodic actions, in-scope inaccessible and underground instrumentation and control cables subject to significant moisture are evaluated to determine whether testing is required. If required, initial testing is performed once on a sample population to determine the condition of the electrical insulation. One or more tests may be required due to cable type, application, and electrical insulation to determine the age-related degradation of the cable. Inaccessible instrumentation and control cables designed for continuous wetting or submergence are also included in this. The need for additional tests and inspections is determined by the test/inspection results as well as industry and plant-specific OE.

Testing of installed inservice inaccessible and underground instrumentation and control cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium- or low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, construction, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible instrumentation and control cables when testing is recommended in this AMP.

As stated in NUREG/CR–5643, “the major concern is that failures of deteriorated cable systems (cables and penetrations) might be induced during accident conditions.” Because the cables are not subject to the EQ requirements of 10 CFR 50.49 (TN249), an AMP is required to manage the aging effects. This AMP provides reasonable assurance that insulation material for electrical cables will perform its intended function for the subsequent period of extended operation.

Evaluation and Technical Basis

1 ***Scope of Program:*** This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) instrumentation and control cables that are within the scope of SLR and are potentially exposed to significant moisture.

For this AMP, instrumentation cables are cables carrying either analog or digital signals such as coaxial cable, or cable comprising twisted 16 or 18 American wire gauge (AWG) conductor shielded pairs rated at 300 V with an overall shield. Examples of control cables included in this AMP are multi-conductor 600 V 12 or 14 AWG cables used to monitor or initiate control functions through indication, switches, limit switches, relays, contacts, etc.

Significant moisture is defined as exposure to moisture that lasts more than 3 days that, if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

In-scope inaccessible and underground instrumentation and control cable splices subjected to wetting or submergence are included within the scope of this program. Cables designed for continuous wetting or submergence also are included in this AMP. Additional tests and periodic visual inspections are determined by the test/inspection results and industry and plant-specific aging degradation OE with the applicable cable electrical insulation.

2 ***Preventive Actions:*** This is a condition monitoring program. However, periodic actions are taken to prevent inaccessible and underground instrumentation and control cables from being exposed to significant moisture, such as identifying and inspecting in-scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and removing the water, as needed.

The inspection frequency for water accumulation in manholes/vaults is established and performed based on plant-specific OE with cable wetting or submergence. The inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually, and the first inspection for SLR is completed prior to the subsequent period of extended operation. The annual inspection frequency is consistent with NRC Inspection Manual, Attachment 71111.06, “Flood Protection Measures.” Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pumpout of accumulated water prior to the wetting or submergence of cables can be performed at least once every 5 years, if supported by plant OE. Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or the control room. The reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

Inspections for water accumulation are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. Inspections of manholes equipped with water level monitoring and alarms are performed after event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Plant-specific parameters are established for the initiation of an event-driven inspection. Inspections include direct indication that cables are not submerged, and that cable/splices and cable support structures are intact. Dewatering systems (e.g., sump pumps and passive drains) and associated alarms are inspected and their operation verified periodically. The periodic inspection includes documentation that either automatic or passive drainage systems, or manual pumping of manholes or vaults is effective in preventing inaccessible cable exposure to significant moisture.

The aging management of the physical structure, including cable support structures and cable vaults or manholes, is managed by Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.S6, “Structures Monitoring.”

3 ***Parameters Monitored or Inspected:*** Inspection for water accumulation in manholes/vaults is performed periodically based on plant-specific OE with water accumulation over time.

Inaccessible and underground instrumentation and control cables within the scope of SLR are periodically visually inspected to assess age-related degradation of the electrical insulation. Inaccessible and underground instrumentation and control cables found to be exposed to significant moisture are evaluated (e.g., a determination is made as to whether a periodic or one-time test is needed for condition monitoring of the cable insulation system). Cable installation systems that are known or subsequently found through either industry or plant-specific OE to degrade with continuous exposure to significant moisture (e.g., Vulkene and Raychem cross-linked polyethylene) are also tested to monitor cable electrical insulation degradation over time. The specific type of test(s) should be a proven technique capable of detecting reduced insulation resistance or degraded dielectric strength of the cable insulation system due to wetting or submergence.

Visual inspection of inaccessible and underground instrumentation and control cables also includes a determination about whether other adverse environments exist. Cables subjected to these adverse environments are also evaluated for significant aging degradation of the cable insulation system.

The reliability, self-monitoring features, and operation of continuous water level and alarm capabilities of such devices, if installed and credited 5-year inspection intervals, are demonstrated routinely depending on the attributes of the specific equipment used.

4 ***Detection of Aging Effects:*** For inaccessible instrumentation and control cables exposed to significant moisture, visual inspection frequency is adjusted based on inspection and test results as well as plant-specific and industry OE. For inaccessible and underground instrumentation and control cables exposed to significant moisture where testing is required, a one-time test is performed. Visual inspection occurs at least once every 6 years and may be coordinated with the periodic inspection for water accumulation. This is an adequate period during which to monitor the performance of instrumentation and control cables and take appropriate corrective actions because industry OE has shown that although a it is slow process, age-related degradation could be significant. Required testing and the initial visual inspection for SLR are to be completed prior to the subsequent period of extended operation.

Cables are periodically visually inspected for cable jacket surface abnormalities, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the AMP considers age-related degradation of the cable jacket material to be representative of the aging effects experienced by the instrumentation and control cable electrical insulation. Age-related degradation of the cable jacket may indicate accelerated age degradation of the electrical insulation due to significant moisture or other aging mechanisms.

The specific type of test(s) determines, with reasonable assurance, in-scope inaccessible instrumentation, and control cable insulation age-related degradation. One or more tests may be required based on cable application, and electrical insulation material to determine the age-related degradation of the cable insulation.

Testing of installed inservice inaccessible instrumentation and control cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium- or low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible instrumentation and control cables when testing is required in this AMP.

The cable testing portion of the AMP uses sampling. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. The basis for the methodology and sample used is documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made about whether the same condition or situation is applicable to other inaccessible instrumentation and control cables not tested and whether the tested sample population should be expanded. The applicant’s corrective action program is used to evaluate test or visual inspection results that did not meet the acceptance criteria and determine appropriate corrective action (e.g., additional visual inspections or testing).

5 ***Monitoring and Trending:*** Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. However, condition monitoring cable tests and inspection results that use the same visual or test methods that are trendable and repeatable provide additional information about the rate of cable insulation degradation.

6 ***Acceptance Criteria:*** An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of intended function.

The acceptance criteria for each test or inspection are determined by the specific type of test performed and the specific cable tested. Acceptance criteria for water accumulation inspections are defined by the direct indication that cable support structures are intact and cables are not subject to significant moisture. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected, and their operation is verified. Proper and reliable operation, as well as the self-monitoring features of continuous water level and alarm capabilities of such devices, if installed and credited with 5-year inspection intervals, are demonstrated routinely according to the requirements and attributes of the specific equipment used.

Visual inspection results show that instrumentation and control cable jacket material are free from unacceptable surface abnormalities that indicate excessive cable insulation aging degradation.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

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XI.E3C ELECTRICAL INSULATION FOR INACCESSIBLE LOW-VOLTAGE POWER CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

The purpose of this aging management program (AMP) is to provide reasonable assurance that the intended functions of inaccessible or underground low-voltage alternating current (AC) and direct current (DC) power cables (i.e., typical operating voltage of less than 1,000 V, but no greater than 2 kV) that are not subject to the environmental qualification (EQ) requirements of Title 10 of the *Code of Federal Regulations (*10 CFR) 50.49 (TN249) are maintained consistent with the current licensing basis through the subsequent period of extended operation.

This AMP applies to all underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) low-voltage power cables, including those designed for continuous wetting or submergence, within the scope of subsequent license renewal (SLR) and are potentially exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days that, if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

When an inaccessible low-voltage power cable is exposed to wet, submerged, or other environments for which it was not designed, accelerated age-related degradation of the electrical insulation may occur. The risk contribution due to a failure of a low-voltage power cable may be limited due to system architecture. However, a common environmental aging stressor such as submergence represents an aging mechanism that, if not anticipated in the design or mitigated in service, could have an adverse effect on operability, may lead to multiple random failures of the cable insulation system, and compromise system defense-in-depth.

Periodic actions are taken to prevent inaccessible low-voltage power cables from being exposed to significant moisture. Examples of periodic actions include inspecting for water accumulation in cable manholes, vaults, conduits, and removing water, as needed. Low-voltage power cables accessible from manholes, vaults, or other underground raceways are visually inspected for cable surface abnormalities. However, these periodic actions may not be sufficient due to the inability to remove accumulated water trapped in the raceways. For example, water accumulation or submergence could occur as a result of (1) a duct bank conduit with low points in the routing, (2) raceway settling or cracking due to soil settling over a long period of time, (3) manholes and cable trench covers not being watertight, (4) raceway locations subject to a high water table (e.g., high seasonal cycles), and (5) potential wetting or submergence even when duct banks are sloped with the intention to minimize water accumulation.

Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pumpout of accumulated water prior to the wetting or submergence of cables can be performed at least once every 5 years, if supported by plant operating experience (OE). Inspections of manholes equipped with water level monitoring and alarms are also performed after event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or in the control room. The reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

In addition to the above periodic actions, in-scope inaccessible and underground low-voltage power cables subject to significant moisture are evaluated to determine whether testing is required. If required, initial testing is performed once on a sample population to determine the condition of the electrical insulation. One or more tests may be required due to cable type, application, and electrical insulation to determine the age-related degradation of the cable. Inaccessible low-voltage power cables designed for continuous wetting or submergence are also included in this AMP. The need for additional periodic tests and inspections is determined by the test and inspection results, as well as, industry and plant-specific OE.

Testing of installed inservice inaccessible and underground low-voltage power cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, construction, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible low-voltage power cables when testing is recommended in this AMP.

As stated in NUREG/CR–5643, “the major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions.” Because the cables are not subject to the EQ requirements of 10 CFR 50.49 (TN249), an AMP is required to manage the aging effects. This AMP provides reasonable assurance that insulation material for electrical cables will perform its intended function for the subsequent period of extended operation.

Evaluation and Technical Basis

1 ***Scope of Program:*** This AMP applies to underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) low-voltage power cables that are within the scope of SLR and are potentially exposed to significant moisture. For this AMP, low-voltage AC and DC power cables are considered in-scope cables with typical operating voltage of less than 1,000 V, but no greater than 2 kV.

Significant moisture is defined as exposure to moisture that lasts more than 3 days that, if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

In-scope inaccessible and underground low-voltage power cable splices subjected to wetting or submergence are included within the scope of this program. Cables designed for continuous wetting or submergence also are included in this AMP. Additional tests and periodic visual inspections are determined by the test/inspection results and industry and plant-specific aging degradation OE with the applicable cable electrical insulation.

2 ***Preventive Actions:*** This is a condition monitoring program. However, periodic actions are taken to prevent inaccessible and underground low-voltage power cables from being exposed to significant moisture, such as identifying and inspecting in-scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and removing the water, as needed.

The inspection frequency for water accumulation in manholes/vaults is established and performed based on plant-specific OE with cable wetting or submergence. The inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually, and the first inspection for SLR is completed prior to the subsequent period of extended operation. The annual inspection frequency is consistent with U.S. Nuclear Regulatory Commission Inspection Manual, Attachment 71111.06, "Flood Protection Measures." Inspection of manholes equipped with water level monitoring and alarms that result in consistent and subsequent pumpout of accumulated water prior to wetting or submergence of cables can be performed at least once every 5 years, if supported by plant OE. Credit for water level monitoring equipment can be taken if such devices have continuous self-monitoring features and generate failure alarms at a central location or in the control room. The reliability and methods of ensuring continuous operation of level monitoring devices are justified and documented.

Inspections for water accumulation are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. Inspections of manholes equipped with water level monitoring and alarms are performed after event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent water level alarms). Plant-specific parameters are established for the initiation of an event-driven inspection. Inspections include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact. Dewatering systems (e.g., sump pumps and passive drains) and associated alarms are inspected, and their operation verified periodically. The periodic inspection includes documentation that either automatic or passive drainage systems, or manually pumping of manholes or vaults is effective in preventing inaccessible cable exposure to significant moisture.

The aging management of the physical structure, including cable support structures, of cable vaults/manholes is managed by Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.S6, "Structures Monitoring."

3 ***Parameters Monitored or Inspected:*** Inspection for water accumulation in manholes/vaults is performed based on plant-specific OE with water accumulation over time.

Inaccessible and underground low-voltage power cables within the scope of SLR are periodically visually inspected to assess the age-related degradation of the electrical insulation. Inaccessible and underground low-voltage power cables found to be exposed to significant moisture are evaluated (e.g., a determination is made about whether a periodic or one-time test is needed for condition monitoring of the cable insulation system). Cable installation systems that are known or subsequently found through either industry or plant-specific OE to degrade with continuous exposure to significant moisture (e.g., Vulkene and Raychem cross-linked polyethylene) are also tested to monitor cable electrical insulation degradation over time. The specific type of test(s) should be a proven technique capable of detecting reduced insulation resistance or degraded dielectric strength of the cable insulation system due to wetting or submergence.

Visual inspection of inaccessible and underground low-voltage power cables also includes a determination about whether other adverse environments may exist. Cables subjected to these adverse environments are also evaluated for significant aging degradation of the cable insulation system.

The reliability, self-monitoring features, and operation of continuous water level and alarm capabilities of such devices, if installed and credited for 5-year inspection intervals, are demonstrated routinely depending on the attributes of the specific equipment used.

4 ***Detection of Aging Effects:*** For inaccessible low-voltage power cables exposed to significant moisture, the visual inspection frequency is determined based on inspection and test results as well as plant-specific and industry OE. For inaccessible and underground low-voltage power cables exposed to significant moisture where testing is required, a one-time test is performed. Visual inspection occurs at least once every 6 years and may be coordinated with the periodic inspection for water accumulation. This is an adequate period during which to monitor the performance of low-voltage power cables and take appropriate corrective actions because industry OE has shown that although it is a slow process, age-related degradation could be significant. Required testing and the initial visual inspection for SLR are to be completed prior to the subsequent period of extended operation.

Cables are periodically visually inspected for cable jacket surface abnormalities such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the AMP considers the degradation of the cable jacket material to be representative of the aging effects experienced by the low-voltage power cable electrical insulation. Age-related degradation of the cable jacket may indicate accelerated age-related degradation of the electrical insulation due to significant moisture or other aging mechanisms.

The specific type of test(s) determines, with reasonable assurance, in-scope inaccessible low-voltage power cable insulation age-related degradation. One or more tests may be required based on cable application, and electrical insulation material to determine the age-related degradation of the cable insulation.

Testing of installed inservice low-voltage power cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power cables or instrumentation and control cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible low-voltage power cables when testing is required in this AMP.

The cable testing portion of the AMP uses sampling. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. The basis for the methodology and sample used is documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made about whether the same condition or situation is applicable to other inaccessible low-voltage power cables not tested and whether the tested sample population should be expanded. The applicant's corrective action program is used to evaluate test or visual inspection results that did not meet the acceptance criteria and determine appropriate corrective action (e.g., additional visual inspections or testing).

5 ***Monitoring and Trending:*** Where practical, degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. However, condition monitoring cable tests and visual inspection results that use the same visual or test methods that are trendable and repeatable provide additional information about the rate of cable insulation degradation.

6 ***Acceptance Criteria:*** An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of intended function.

he acceptance criteria for each test or inspection are determined by the specific type of test performed and the specific cable tested. Acceptance criteria for water accumulation inspections are defined by the direct indication that cables/splices and cable support structures are intact and cables are not subject to significant moisture. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected and their operation verified. Proper and reliable operation, as well as the self-monitoring features of continuous water level and alarm capabilities of such devices, if installed and credited for 5-year inspection intervals, are demonstrated routinely according to the requirements and attributes of the specific equipment used.

Visual inspection results show that low-voltage power cable jacket material is free from unacceptable surface abnormalities that indicate excessive cable insulation aging degradation.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

~~Additional inspections are conducted if one of the inspections does not meet the acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the site's corrective action process; however, there are no fewer than two additional inspections for each inspection that did not meet the acceptance criteria. The additional inspections are completed within the interval (e.g., refueling outage interval, 10-year inspection interval) induring which the original inspection was conducted. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. At multi-unit sites, the additional inspections include inspections at all of the units withthat have the same material, environment, and aging effect combination.~~

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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XI.E4 METAL ENCLOSED BUS

Program Description

The purpose of this aging management program (AMP) is to provide an internal and external inspection of metal enclosed buses (MEBs) within the scope of subsequent license renewal (SLR) to identify age-related degradation of electrical insulating material (i.e., porcelain, xenoy, thermoplastic organic polymers), and metallic and elastomer components (e.g., gaskets, boots, and sealants). This AMP provides reasonable assurance that in-scope MEBs will be maintained consistent with the current licensing basis (CLB) through the subsequent period of extended operation.

MEBs are electrical buses installed on electrically insulated supports that are constructed with each phase conductor enclosed in a separate metal enclosure (isolated phase bus), all conductors enclosed in a common metal enclosure (nonsegregated bus), or all phase conductors in a common metal enclosure, but separated by metal barriers between phases (segregated bus). The conductors are adequately separated and insulated from ground by insulating supports or bus electrical insulation. The MEBs are used in power systems to connect various elements in electric power circuits, such as switchgear, transformers, main generators, and diesel generators.

Industry operating experience (OE) indicates that the primary failure modes of MEBs have been caused by cracked electrical insulation, moisture, debris, loose connections, corrosion, or excessive dust buildup internal to the bus housing. Cracked insulation has resulted from high ambient temperature and contamination from bus bar joint compounds. Cracked electrical insulation in the presence of moisture or debris has caused phase-to-phase or phase-to-ground electrical paths, which has resulted in catastrophic failure of the buses. Significant ohmic heating of the bus may result in loosening of bolted connections associated with repeated cycling of connected loads. Bus failure has led to loss of power to electrical loads connected to the buses, causing subsequent reactor trips and initiating unnecessary challenges to plant systems and operators.

MEBs may experience increased resistance of connection due to loosening of bolted bus duct connections caused by repeated thermal cycling of connected loads. This phenomenon can occur in heavily loaded circuits (i.e., those exposed to appreciable ohmic heating). For example, SAND96-0344 (TN8005) identified instances of termination loosening at several plants due to thermal cycling and U.S. Nuclear Regulatory Commission Information Notice 2000-14 identified torque relaxation of splice plate connecting bolts as one potential cause of MEB failures.

This AMP includes the inspection of accessible bus ducts and a sample of MEB bolted connections within the scope of license renewal for increased resistance of connections.

Evaluation and Technical Basis

1 ***Scope of Program:*** This AMP manages the age-related degradation effects for electrical bus bar bolted connections, bus bar electrical insulation, bus bar insulating supports, bus enclosure assemblies (internal and external), and elastomers. This program does not manage the aging effects on external bus structural supports, which are managed under Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.S6, “Structures Monitoring.” Alternatively, the aging effects on elastomers can be managed under GALL-SLR Report AMP XI.M38, “Inspection of Internal Surfaces in

Miscellaneous Piping and Ducting Components," and the external surfaces of MEB enclosure assemblies can be managed under GALL-SLR Report AMP XI.S6, "Structures Monitoring." Cable bus arrangements, as described in GALL-SLR Chapter VI Table A, "Electrical Components – Equipment Not Subject to 10 CFR 50.49 (TN249) Environmental Qualification Requirements," are excluded from this AMP and are evaluated as a site-specific further evaluation item per Section 3.6.2.2.2 of the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants.

2 ***Preventive Actions:*** This is a condition monitoring program and no actions are taken as part of this program to prevent or mitigate aging degradation.

3 ***Parameters Monitored or Inspected:*** This AMP provides for the inspection of the internal and external portions of the MEB. Internal portions (bus enclosure assemblies) of the MEB are inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus electrical insulation material is inspected for signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, or ohmic heating, as indicated by embrittlement, cracking, chipping, melting, discoloration, or swelling, which may indicate overheating or aging degradation. The internal bus insulating supports are inspected for structural integrity and signs of cracks. A sample of bolted connections is inspected for increased resistance of connection (e.g., loose or corroded MEB bolted connections and hardware including cracked or split washers). Alternatively, a sample of bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., may be visually inspected for electrical insulation material surface abnormalities. The external portions of the MEB, including accessible gaskets, boots, and sealants, are inspected for hardening or loss of strength due to elastomer degradation that could permit water or foreign debris to enter the bus. MEB external surfaces are inspected for loss of material due to general, pitting, and crevice corrosion.

MEBs are generally accessible structures and as such are inspected and tested in their entirety. However, depending on particular plant configurations, some segments of the MEB may be considered inaccessible due to their close proximity to other permanent structures (e.g., nearby walls, ducts, cable trays, equipment or other structural elements). For inaccessible MEB internal or external segments, the applicant demonstrates (e.g., through alternative analysis, inspection, test, or plant OE) that the inaccessible MEB segments evaluation, together with the accessible MEB inspection and test program, will continue to maintain the MEB consistent with the CLB during the subsequent period of extended operation.

4 ***Detection of Aging Effects:*** MEB internal surfaces are visually inspected for aging degradation including cracks, corrosion, foreign materials debris, excessive dust buildup, and evidence of moisture intrusion. MEB insulating material is visually inspected for signs of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. Internal bus insulating supports are visually inspected for structural integrity and signs of cracks. MEB external surfaces are visually inspected for loss of material due to general, pitting, and crevice corrosion. Accessible elastomers (e.g., gaskets, boots, and sealants) are inspected for degradation including surface cracking, crazing, scuffing, dimensional change (e.g., "ballooning" and "necking"), shrinkage, discoloration, hardening or loss of strength.

A sample of accessible bolted connections is inspected for increased resistance of connection by using thermography or by measuring connection resistance using a micro ohmmeter. Twenty percent of the population with a maximum sample size of 25 constitutes a representative sample size. When thermography is employed by the applicant, the applicant demonstrates with a documented evaluation that the thermography is effective in identifying MEB increased resistance of connection (e.g., infrared viewing windows installed, or demonstrated test equipment capability). In addition to thermography or resistance measurement, bolted connections not covered with heat shrink tape or boots are visually inspected for increased resistance of connection (e.g., loose or corroded bolted connections and hardware including cracked or split washers).

The first inspection for measuring connection resistance or thermography is completed prior to the subsequent period of extended operation and every 10 years thereafter. This is an adequate period of time to preclude failures of the MEBs because experience has shown that MEB aging degradation is a slow process.

As an alternative to thermography or measuring connection resistance of bolted connections, for accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., the applicant may use visual inspection of insulation material to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. When an alternative visual inspection is used to check MEB bolted connections, the first inspection is completed prior to the subsequent period of extended operation and every 5 years thereafter.

5 ***Monitoring and Trending:*** Trending actions are not included as part of this AMP because the ability to trend inspection results is limited. However, results that are trendable provide additional information about the rate of degradation.

6 ***Acceptance Criteria:*** An unacceptable condition is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of the intended function.

MEB electrical insulation materials are free from unacceptable regional indications of surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. MEB internal surfaces show no indications of unacceptable corrosion, cracks, foreign debris, excessive dust buildup, or evidence of moisture intrusion. Accessible elastomers (e.g., gaskets, boots, and sealants) show no indications of unacceptable surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength. MEB external surfaces are free from unacceptable loss of material due to general, pitting, and crevice corrosion.

MEB bolted connections are below the maximum allowed temperature (e.g., comparison of compartment temperatures, trending of temperature over time, or comparison to a baseline thermography signature) for the application when thermography is used, or a low resistance value appropriate for the application when resistance measurement is used.

When the visual inspection alternative for MEB bolted connections is used, the absence of embrittlement, cracking, chipping, melting, discoloration, swelling, surface contamination of the electrical insulation material provides positive indication that the bolted connections are not loose. Visual inspection of bolted connections not covered with heat shrink tape, sleeving, insulating boots, etc. are free from corrosion, loose connections and hardware including cracked or split washers.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Corrective actions are taken and an engineering evaluation is performed when the acceptance criteria are not met. Corrective actions may include, but are not limited, to cleaning, drying, increased inspection frequency, replacement, or repair of the affected MEB components. An engineering evaluation is performed when the acceptance criteria are not met to demonstrate that the MEB intended function can be maintained consistent with the CLB. The engineering evaluation considers the significance of the surveillance, inspection, or test results on the performance of intended functions, the extent of the concern, the potential root causes for not meeting the acceptance criteria, the corrective actions required, and the likelihood of recurrence. If an unacceptable condition or situation is identified, (e.g., internal surface degradation including cracks, corrosion, foreign debris, excessive dust buildup, moisture intrusion, insulating material embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination) a determination is made about whether the same condition or situation is applicable to MEB bolted connections not inspected or tested. Further, when acceptance criteria are not met, a determination is made about whether the surveillance, inspection, or test, including frequency intervals, needs to be modified.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Industry experience has shown that failures have occurred on MEBs caused by cracked electrical insulation and moisture or debris buildup internal to the MEB. Experience also has shown that bus connections in the MEBs exposed to appreciable ohmic heating during operation may experience loosening due to repeated cycling of connected loads.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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XI.E5 FUSE HOLDERS

Program Description

The purpose of this aging management program (AMP) is to provide reasonable assurance that the intended functions of fuse holders within the scope of subsequent license renewal (SLR) and subject to aging management are maintained consistent with the current licensing basis. The fuse holder program was developed specifically to address the aging management of fuse holder insulation material and fuse holder metallic clamp aging mechanisms and effects. This AMP uses visual inspection and testing to identify age-related degradation of both fuse holder electrical insulation material and fuse holder metallic clamps. Visual inspection and testing provide reasonable assurance that the applicable aging effects are identified and fuse holder insulators and metallic clamps are age managed.

Fuse holders (fuse blocks) are classified as a specialized type of terminal block because of the similarity of fuse holder design and construction to that of a terminal block. Fuse holders are typically constructed of blocks of rigid insulating material, such as phenolic resins. Metallic clamps (clips) are attached to the blocks to hold each end of the fuse. The clamps, which are typically made of copper, can be spring-loaded clips or bolt lugs to which the fuse ends are connected.

Industry operating experience (OE) has shown that repetitive removal and reinsertion of fuses during maintenance or surveillance activities can lead to degradation of the fuse holders. Fuse holders, located outside of active equipment, where fuses are removed and replaced frequently for maintenance or surveillance activities, are also included in this AMP to manage these repetitive activities.

The metallic portions of fuse holders that are within the scope of SLR and are subject to aging management are tested for the following aging stressors: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and insertion, or vibration. The specific type of test is determined prior to conducting the initial test and detects increased resistance of fuse holder metallic clamp connections. Tests may include thermography, contact resistance testing, or other appropriate testing justified in the application.

Fuse holders within the scope of SLR and subject to aging management are visually inspected to provide an indication of the condition of the electrical insulation portion of the fuse holders. Fuse holders are visually inspected for electrical insulation surface anomalies indicating signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis and photolysis (ultraviolet [UV]-sensitive materials only) of organics, radiation-induced oxidation, and moisture intrusion as indicated by signs of embrittlement, discoloration, cracking, melting, swelling, or surface contamination.

As stated in NUREG–1760, “Aging Assessment of Safety-Related Fuses Used in Low and Medium-Voltage Applications in Nuclear Power Plants,” licensees have experienced a number of age-related failures. The major concern is that failures of a deteriorated cable system (cables, connections including fuse holders, and penetrations) might be induced during accident conditions. Because these cable systems are not subject to the environmental qualification requirements of Title 10 of the *Code of Federal Regulations* (10 CFR) 50.49, an AMP is required to manage their aging effects. This AMP demonstrates that fuse holders, including both the insulation and metallic components will maintain the ability to perform their intended function for the subsequent period of extended operation.

Evaluation and Technical Basis

1 ***Scope of Program:*** This AMP manages in-scope fuse holders outside of active devices that are considered susceptible to the following aging effects: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement, or vibration. It also manages degradation of electrical insulation for the fuse holders that have metallic clamps that are susceptible to the aging effects identified. Fuse holders inside an active device (e.g., switchgears, power supplies, inverters, battery chargers, and circuit boards) and not subject to the aging effects identified are not within the scope of this AMP.

2 ***Preventive Actions:*** This is a condition monitoring program and no actions are taken as part of this program to prevent or mitigate aging degradation.

3 ***Parameters Monitored or Inspected:*** The metallic clamp portion of the fuse holder is tested to detect any increased resistance of the connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement or vibration. The electrical insulation material portion of the fuse holder is visually inspected to identify insulation surface anomalies, indicating signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis and photolysis (UV-sensitive materials only) of organics, radiation-induced oxidation, and moisture intrusion as indicated by signs of embrittlement, discoloration, cracking, melting, swelling, or surface contamination.

4 ***Detection of Aging Effects:*** Fuse holders within the scope of this AMP are visually inspected and tested at least once every 10 years to provide an indication of the condition of the metallic clamp of the fuse holder. Testing may include thermography, contact resistance testing, or other appropriate testing methods. Visual inspection includes inspection for electrical insulation surface anomalies indicating signs of reduced insulation resistance. Visual inspection and testing at least once every 10 years is an adequate period to preclude failures of the fuse holders since experience has shown that aging degradation is a slow process. The first visual inspections and tests for SLR are to be completed prior to the subsequent period of extended operation.

5 ***Monitoring and Trending:*** Trending actions are not included as part of this AMP because the ability to trend visual inspection and test results is dependent on the inspection and specific type of test chosen. However, results that are trendable provide additional information about the rate of degradation.

6 ***Acceptance Criteria:*** An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of intended function.

The acceptance criteria for each visual inspection and test are defined by the specific type of inspection or test performed and the specific type of fuse holder tested. When thermography is used, the metallic clamp of the fuse holder needs to be below the maximum allowed temperature for the application; otherwise, a low resistance value appropriate for the application is applicable when resistance measurement is used. Test acceptance criteria show that fuse holders are free from the unacceptable aging effects of increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement, or vibration. Visual inspection acceptance criteria show that fuse holders are free from unacceptable electrical insulation surface anomalies indicating signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis and photolysis (UV-sensitive materials only) of organics, radiation-induced oxidation, and moisture intrusion as indicated by signs of embrittlement, discoloration, cracking, melting, swelling, or surface contamination.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 **Operating Experience*:*** OE has shown that loosening of fuse holder metallic clamps due to chemical contamination, corrosion, oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement, vibration, and electrical insulation surface (i.e., fuse blocks) abnormalities are aging mechanisms indicating signs of reduced insulation resistance. If left unmanaged, these aging mechanisms can lead to a loss of function. NUREG–1760 documents fuse holder failures due to fatigue and recommends the review of maintenance procedures (e.g., fuse control programs) to minimize removal and reinsertion of fuses to de-energize components (because this can lead to degradation of the fuse holder assembly).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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XI.E6 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

The purpose of the this aging management program (AMP) is to provide reasonable assurance that the intended functions of the metallic parts of electrical cable connections that are not subject to the environmental qualification (EQ) requirements of Title 10 of the *Code of Federal Regulations* (10 CFR) 50.49 (TN249) and susceptible to age-related degradation resulting in increased resistance of the connection are maintained consistent with the current licensing basis through the subsequent period of extended operation. This AMP manages the aging mechanisms and effects associated with the metallic portion of electrical connections that result in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation such that the metallic portions of the electrical cable connections are maintained consistent with the current licensing basis through the subsequent period of extended operation.

Cable connections are used to connect cable conductors to other cable conductors or electrical devices. Connections associated with cables within the scope of license renewal are part of this AMP. Examples of connections used in nuclear power plants include bolted connectors, coaxial/triaxial connections, compression/crimped connectors, splices (butt or bolted), stress cones, and terminal blocks. Most connections involve insulating material and metallic parts. This AMP focuses on the metallic parts of the electrical cable connections. This AMP provides testing, on a sampling basis, to demonstrate that either aging of metallic cable connections is not occurring and/or that the existing preventive maintenance program is effective. Testing confirms the absence of age-related degradation of cable connections resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation.

The Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.E1, “Electrical Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” manages the aging of insulating material but not the metallic parts of the electrical connections. The GALL-SLR Report AMP X1.E1 is based on a visual inspection of accessible cables and connections. However, visual inspection alone may not be sufficient to detect the aging effects from thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation on the metallic parts of cable connections.

Electrical cable connections exposed to appreciable ohmic or ambient heating during operation may experience increased resistance of connection caused by repeated cycling of connected loads or by the ambient temperature environment. Different materials used in various cable system components can produce situations where stresses between these components change with repeated thermal cycling. For example, under loaded conditions, ohmic heating may raise the temperature of a compression terminal and cable conductor well above the ambient temperature, thereby causing thermal expansion of both components. Thermal expansion coefficients of different materials may alter mechanical stresses between the components and may adversely affect the termination. When the current is reduced, the affected components cool and contract. Repeated cycling in this fashion can cause loosening of the termination and may lead to increased resistance of connection or eventual separation of compression type terminations. Threaded connectors may also loosen if subjected to significant thermally induced stress and cycling.

A sample of cable connections within the scope of license renewal is tested on a one-time test basis or periodically once every 5 years, if only visual inspection is used to provide an indication of the integrity of the cable connections. Depending on the findings of the one-time test, subsequent testing may have to be performed within 10 years of initial testing. The first visual inspections or tests for license renewal are to be completed prior to the subsequent period of extended operation.

The specific type of test to be performed is a proven test for detecting increased resistance of connection, such as thermography, contact resistance testing, or another appropriate test. As an alternative to measurement of cable connections, for the accessible cable connections that are covered with insulation materials such as tape, the applicant may perform visual inspection of insulation material to detect aging effects. The basis for performing only a periodic visual inspection is documented.

This AMP is a sampling program. The following factors are considered for sampling: voltage level (medium and low), circuit loading (high loading), connection type, and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selections should be documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made about whether the same condition or situation is applicable to other connections not tested. The corrective action program is used to evaluate the condition and determine appropriate corrective action.

This AMP is not applicable to cable connections in harsh environments because they are already addressed by the requirements of 10 CFR 50.49. Even though cable connections may not be exposed to harsh environments, increased resistance of the connection is a concern due to the cable connection aging mechanisms and effects discussed above.

Evaluation and Technical Basis

1. ***Scope of Program:*** Cable connections associated with cables within the scope of license renewal that are external connections terminating at active or passive devices, are in the scope of this AMP. Wiring connections internal to an active assembly are considered part of the active assembly and, therefore, are not within the scope of this AMP. This AMP does not include high-voltage (>35 kV) switchyard connections. The cable connections covered under the EQ program are not included in the scope of this program.

2. ***Preventive Actions:*** This is a condition monitoring program, and no actions are taken as part of this program to prevent or mitigate aging degradation.

3. ***Parameters Monitored or Inspected:*** This AMP focuses on the metallic parts of the connection. One-time testing provides an indication of increased resistance of the connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation. Representative samples of each type of electrical cable connection are tested. The following factors are considered for sampling: voltage level (medium and low), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selection is documented.

4. ***Detection of Aging Effects:*** A representative sample of electrical connections within the scope of license renewal is tested prior to the subsequent period of extended operation. The findings of the initial one-time test are evaluated to determine whether periodic testing of the cable connections is warranted. This finding forms the basis of site-specific operating experience (OE) for age-related degradation and informs the need for subsequent testing on

a 10-year periodic basis. The justification and technical basis for not performing subsequent periodic testing is documented. This includes a discussion of the types of unacceptable conditions or degradation identified and whether they were determined to be age-related, requiring periodic maintenance.

Testing of in-scope connections manages the aging mechanisms and effects requiring management during the subsequent period of extended operation. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. One-time testing 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. Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. Otherwise a technical justification of the methodology and sample size used for selecting components under test should be included as part of the applicant’s AMP’s documentation.

The first tests for license renewal are to be completed prior to the subsequent period of extended operation.

As an alternative to measurement testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., the applicant may use a visual inspection of insulation materials to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination. When this alternative visual inspection is used to check cable connections, the first inspection is completed prior to the subsequent period of extended operation and at least every 5 years thereafter. The basis for performing only the alternative periodic visual inspection to monitor age-related degradation of cable connections is documented.

5 ***Monitoring and Trending:*** Trending actions are not included as part of this AMP because the ability to trend visual inspection and test results is dependent on the specific test or visual inspection program selected. However, condition monitoring inspection or test results that are trendable provide additional information about the rate of electrical connection degradation.

6 ***Acceptance Criteria:*** Cable connections should not indicate abnormal temperatures for the application when thermography is used. Alternatively, connections should exhibit a low resistance value appropriate for the application when resistance measurement is used. When the visual inspection alternative for covered cable connections is used, the absence of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination indicates that the covered cable connection components are not loose. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of intended function.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50 (TN249), Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Electrical cable connections exposed to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation during operation may experience increased resistance of connection. A limited number of age-related failures of cable connections have been reported. An applicant's OE with connection reliability and aging effects should be adequate to demonstrate the AMP effectiveness of GALL-SLR Report AMP XI.E6, "Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," including the program's capability to detect the presence or note the absence of aging effects for electrical cable connections.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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NRC. NUREG/CR–5643, “Insights Gained From Aging Research.” ADAMS Accession No. ML041530264. Washington, DC: U.S. Nuclear Regulatory Commission. March 31, 1992.

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XI.E7 HIGH-VOLTAGE INSULATORS

Program Description

The purpose of this aging management program (AMP) is to provide reasonable assurance that the intended functions of high-voltage insulators within the scope of subsequent license renewal (SLR) are maintained consistent with the current licensing basis through the subsequent period of extended operation. The high-voltage insulator program was developed specifically to age manage high-voltage insulators susceptible to aging degradation due to local environmental conditions.

Given that there are multiple standards that define voltage ranges differently, the term “high-voltage” is used descriptively throughout this program to include all insulators used in power systems operating at nominal system voltages greater than 1 kV, equal to or less than 765 kV, and installed on in-scope portions of switchyards, transmission lines, and power systems. This is not intended to redefine “high-voltage” as 1 kV to 765 kV.

The high-voltage insulators program includes visual inspections to identify the degradation of high-voltage insulator sub-component parts; namely, insulation and metallic elements. Visual inspection provides reasonable assurance that the applicable aging effects are identified and high-voltage insulator age-related degradation is managed. Insulation materials used in high-voltage insulators may degrade more rapidly than expected when installed in an environment conducive to accelerated aging. The insulation and metallic elements of high-voltage insulators are made of porcelain, cement, malleable iron, aluminum, and galvanized steel. Significant loss of metallic material can occur due to mechanical wear caused by oscillating movement of insulators due to wind. Surface corrosion in metallic parts may appear due to contamination or where galvanized or other protective coatings are worn. With substantial airborne contamination such as salt, surface corrosion in metallic parts may become significant such that the insulator no longer will support the conductor. Various airborne contaminants such as dust, salt, fog, cooling tower plume, or industrial effluent can contaminate the insulator surface leading to reduced insulation resistance. Excessive surface contaminants or loss of material can lead to insulator flashover and failure.

The most common type of high-voltage insulators used throughout switchyards, transmission lines, and power systems are porcelain. However, polymer and toughened glass high-voltage insulators are also found in some installations and are included in this AMP.

Polymer high-voltage insulators are typically composed of material such as fiberglass, silicone rubber (SIR), ethylene propylene rubber (EPR), epoxy, silicone gel, sealants, ductile iron, aluminum, aluminum alloys, steel, steel alloys, malleable iron, and galvanized metals. Exposure to air-outdoor can cause degradation and aging effects that can result in reduced insulation resistance due to deposits and surface contamination, reduced insulation resistance due to polymer degradation, loss of material caused by wind blowing on transmission conductors, and loss of material due to corrosion—all of which may require aging management. Polymer high-voltage insulators have been shown to have unique failure modes with minimal advance indications. Surface buildup of contamination can be worse for SIR (compared to porcelain insulators) due to absorption by silicone oil, especially in late stages of service life. Typical aging degradation and mechanisms for polymer high-voltage insulators include (but are not limited to) the following:

- deposits and buildup of surface contamination causing reduced insulation resistance, arcing, and flashover
- polymer degradation caused by thermal degradation of organic material, radiolysis and photolysis of ultraviolet (UV)-sensitive material, oxidation, and moisture intrusion
- stress corrosion cracking (SCC) of glass fibers due to sheath degradation
- swelling or peeling of the SIR layer due to chemical contamination
- sheath wetting caused by chemicals absorbed by oil from an SIR compound
- brittle fracture of rods resulting from discharge activity, flashunder, and flashover
- chalking and crazing of insulator surfaces resulting in contamination, arcing, and flashover
- water penetration through the sheath followed by electrical failure
- bonding failure at the rod and sheathing interface, causing peeling
- water ingress through end fittings causing flashunder, corrosion, and fracture of glass fibers.

Additionally, aggressive environment due to bird and rodent presence and excrements, containing chemicals such as uric acid, phosphates, and ammonia, can accelerate degradation.

Toughened glass high-voltage insulators are similar to porcelain high-voltage insulators in design and construction; the chief difference is the materials used to manufacture the porcelain and glass insulating shells. Both materials (porcelain and toughened glass) are ceramics that experience the same external aging effects of reduced insulation resistance from excessive surface contamination. All high-voltage insulators rely on surface rinsing from precipitation or mechanical washing to clean contaminants from the shed surfaces. Porcelain and toughened glass insulators have been in service in the utility industry for more than 60 years worldwide and are considered to be mature technologies, generally standardized, and readily interchangeable with high reliability and low cost. However, unlike porcelain, toughened glass does not experience micro cracks, micro structure defects or crystallographic structure defects. Because of this, the electrical resistance and capacitance of the toughened glass insulator are defined by the chemistry of the glass and the shape and dimensions of the shell and are not drastically affected by aging or time. Also, toughened glass insulators do not experience substantial loss of material as an aging effect.

The high-voltage insulators within the scope of this program are to be visually inspected at a frequency, determined prior to the subsequent period of extended operation, based on plant-specific operating experience (OE) with the specific type of insulator used (i.e., porcelain, polymer, toughened glass). The first inspections for the subsequent period of extended operation are to be completed prior to the subsequent period of extended operation. The high-voltage insulator program provides reasonable assurance that high-voltage insulators will perform their intended function during the subsequent period of extended operation.

Evaluation and Technical Basis

1 ***Scope of Program:*** This AMP manages the age-related degradation effects of high-voltage insulators (operating at nominal system voltages greater than 1 kV and equal to or less than 765 kV) within the scope of SLR, susceptible to airborne contaminants including dust, salt, fog, cooling tower plume, industrial effluent or loss of material. Different categories of high-voltage insulators such as porcelain high-voltage insulators, polymer high-voltage insulators, and toughened glass high-voltage insulators are considered and covered in this AMP.

2 ***Preventive Actions:*** The high-voltage insulators AMP is a condition monitoring program that relies on visual inspections and high-voltage insulator coating and cleaning to manage high-voltage insulator aging effects. High-voltage insulator periodic visual inspections are performed to monitor the buildup of contaminants on the insulator surface. The periodic coating or cleaning of high-voltage insulators limits high-voltage insulator surface contamination.

3 ***Parameters Monitored or Inspected:*** The high-voltage insulators within the scope of this program are visually inspected at a frequency based on plant-specific OE with the particular type insulator. High-voltage insulator surfaces are visually inspected to detect the loss of material and signs of reduced insulation resistance aging effects, including cracks, foreign debris, salt, dust, cooling tower plume and industrial effluent contamination. Metallic parts of the insulator are visually inspected to detect the loss of material due to mechanical wear or corrosion.

4 ***Detection of Aging Effects:*** Visual inspection is used to detect the following two aging degradations: (1) loss of material in the metallic parts due to corrosion and/or frequent movement, and (2) reduced insulation resistance. The loss of material in the metallic parts is due to corrosion caused by contaminants, where galvanized or other protective coatings are worn, and mechanical wear due to wind-induced movement. Reduced insulation resistance can be caused by the presence of insulator surface contamination or weakening of sheathing due to variety of stressors. Visual inspections may be supplemented with infrared thermography inspections to detect high-voltage insulator reduced insulation resistance. Corona cameras may also be employed to detect early signs of corona emissions. The first inspection for SLR is to be completed prior to the subsequent period of extended operation.

5 ***Monitoring and Trending:*** Trending actions are not included as part of this AMP, because the ability to trend visual inspection results is limited. However, inspection results that are trendable provide additional information about the rate of insulator degradation including optimization of inspection frequencies.

6 ***Acceptance Criteria:*** An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of intended function.

High-voltage insulator surfaces are free from unacceptable accumulation of foreign material such as significant salt or dust buildup as well as other contaminants. Metallic parts must be free from significant loss of materials due to pitting, fatigue, crevice, and general corrosion. Polymer high-voltage insulators should not exhibit peeling of silicone rubber sleeves. Acceptance criteria will be based on temperature rise above a reference temperature for the application when thermography is used. The reference temperature will be ambient temperature, or a baseline temperature based on data from the same type of high-voltage insulator being inspected.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Corrective actions are taken and an engineering evaluation is performed when the acceptance criteria are not met. Corrective actions are based on the observed degradation.

The evaluation considers the significance of the inspection results, the extent of the concern, the potential root causes, and the corrective actions required. If an unacceptable condition is identified, a determination is made about whether the same condition or situation is applicable to other high-voltage insulators. Corrective actions are implemented when inspection results do not meet the acceptance criteria.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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XI.M MECHANICAL

XI.M1 ASME SECTION XI INSERVICE INSPECTION, SUBSECTIONS IWB, IWC, AND IWD

Program Description

Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a (TN249) specifies the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, Rules for ISI of Nuclear Power Plant Components for Class 1, 2, and 3 pressure-retaining components and their integral attachments in light-water cooled power plants. The rules of Section XI require a mandatory program of examinations, testing, and inspections to demonstrate adequate safety and to manage deterioration and aging effects. Inspection of these components is covered in Subsections IWB, IWC, and IWD, respectively, in accordance with the applicable plant ASME Code Section XI edition(s) and addenda as required by 10 CFR 50.55a(g)(4).[1] The program generally includes periodic visual, surface, and/or volumetric examination and leakage testing of Class 1, 2, and 3 pressure-retaining components and their integral attachments. Repair/replacement activities for these components are covered in Subsection IWA of the ASME Code.

The ASME Code Section XI ISI program, in accordance with Subsections IWA, IWB, IWC, and IWD, has been shown to be generally effective in managing aging effects in Class 1, 2, and 3 components and their integral attachments in light-water cooled power plants. 10 CFR 50.55a imposes additional conditions and augmentations of ISI requirements specified in the ASME Code, Section XI, and those conditions or augmentations described in 10 CFR 50.55a are included as part of this program. In certain cases, the ASME Code Section XI ISI program is augmented to manage the effects of aging for license renewal and is so identified in the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report.

Evaluation and Technical Basis

1 ***Scope of Program:*** The ASME Code Section XI program provides the requirements for ISI, repair, and replacement of Class 1, 2, and 3 pressure-retaining components and their integral attachments in light-water cooled nuclear power plants. The components within the scope of the program are specified in ASME Code, Section XI, Subsections IWB-1100, IWC-1100, and IWD-1100 for Class 1, 2, and 3 components, respectively. The components described in Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the volumetric and surface examination requirements, but are not exempt from the VT-2 visual examination and pressure testing requirements of Subsections IWB-2500, IWC-2500, and IWD-2500.

2 ***Preventive Actions:*** This is a condition monitoring program; therefore, this program does not implement preventive actions.

3 ***Parameters Monitored or Inspected:*** The ASME Code, Section XI ISI program detects degradation of components by using the examination and inspection requirements specified in ASME Code, Section XI Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 for Class 1, 2, and 3 components, respectively.

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[1] GALL-SLR Report, Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

The program uses three types of examination—visual, surface, and volumetric—in accordance with the requirements of Subsection IWA-2000. Visual VT-1 examination detects discontinuities and imperfections, such as cracks, corrosion, wear, or erosion, on the surface of components. Visual VT-2 examination detects evidence of leakage from pressure-retaining components, as required during the system pressure test. Visual VT-3 examination (1) determines the general mechanical and structural condition of components and their supports by verifying parameters such as clearances, settings, and physical displacements; (2) detects discontinuities and imperfections, such as loss of integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion; and (3) observes conditions that could affect the operability or functional adequacy of constant-load and spring-type components and supports.

Surface examination uses magnetic particle, liquid penetrant, or eddy current examinations to indicate the presence of surface discontinuities and flaws. Volumetric examination uses radiographic, ultrasonic, or eddy current examinations to indicate the presence of discontinuities or flaws throughout the volume of material included in the inspection program.

4 ***Detection of Aging Effects:*** The extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and to detect and repair or replace components before the loss of intended function of the component. Inspection can reveal cracking, loss of material due to corrosion, leakage of coolant, and indications of degradation due to wear or stress relaxation (such as changes in clearances, settings, physical displacements, loose or missing parts, debris, wear, erosion, or loss of integrity at bolted or welded connections).

Class 1, 2, and 3 components are examined and tested as specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1, respectively. The tables specify the extent and schedule of the inspection and examination methods for the components of the pressure-retaining boundaries.

5 ***Monitoring and Trending:*** For Class 1, 2, and 3 components, the inspection schedule of IWB-2400, IWC-2400, and IWD-2400, and the extent and frequency of IWB-2500-1, IWC-2500-1, and IWD-2500-1, respectively, provide for timely detection of degradation. The sequence of component examinations established during the first inspection interval is repeated during each successive inspection interval, to the extent practical. Volumetric and surface examination results are compared with recorded preservice examination and prior inservice examinations. Flaw conditions or relevant conditions of degradation are evaluated in accordance with IWB-3100, IWC-3100, or IWD-3100.

Examinations that reveal indications that exceed the acceptance standards described below are extended to include additional examinations in accordance with IWB-2430, IWC-2430, and IWD-2430 for Class 1, 2, and 3 components, respectively. Examination results that exceed the acceptance standards below are repaired/replaced or accepted by analytical evaluation in accordance with IWB-3600, IWC-3600 or IWD-3600, as applicable. Those items accepted by analytical evaluation are reexamined during the next three inspection periods of IWB-2410 for Class 1 components, IWC-2410 for Class 2 components, and IWD-2410 for Class 3 components.

6 ***Acceptance Criteria:*** Any indication or relevant conditions of degradation are evaluated in accordance with IWB-3000, IWC-3000, and IWD-3000 for Class 1, 2, and 3 components, respectively. Examination results are evaluated in accordance with IWB-3100, IWC-3100, or IWD-3100 by comparing the results with the acceptance standards of IWB-3400 and IWB-3500 for Class 1, IWC-3400 and IWC-3500 for Class 2, and IWD-3400 and IWD-3500 for

Class 3 components. Flaws that exceed the size of allowable flaws, as defined in IWB-3500, IWC-3500 and IWD-3500, may be evaluated by using the analytical procedures of IWB-3600, IWC-3600 and IWD-3600 for Class 1, 2, and 3 components, respectively.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Repair and replacement activities are performed in conformance with IWA-4000.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Because the ASME Code is a consensus document that has been widely used over a long period, it has been shown to be generally effective in managing aging effects in Class 1, 2, and 3 components and their integral attachments in light-water cooled power plants (see Chapter I of the GALL-SLR Report).

Some specific examples of operating experience (OE) of component degradation are as follows:

- ***Boiling water reactor (BWR):*** Cracking due to intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic stainless steel (SS) and nickel alloys. IGSCC has also occurred in a number of vessel internal components, such as core shrouds, access hole covers, top guides, and core spray spargers [U.S. Nuclear Regulatory Commission (NRC) Inspection and Enforcement Bulletin (IEB) 80-13, NRC Information Notice (IN) 95-17, NRC Generic Letter (GL) 94-03, and NUREG–1544]. Cracking due to thermal and mechanical loading has occurred in high-pressure coolant injection piping (NRC IN 89-80) and instrument lines (Licensee Event Report [LER] 249/99-003-01). BWR jet pumps are designed with access holes in the shroud support plate at the bottom of the annulus between the core shroud and the reactor vessel wall. These holes are used for access during construction and are subsequently closed by welding a plate over the hole. Both circumferential (NRC IN 88-03) and radial cracking (NRC IN 92-57) have been observed in access hole covers. Failure of the isolation condenser tube bundles due to thermal fatigue and transgranular stress corrosion cracking (SCC) caused by leaky valves has also occurred (NRC LER 219/98-014-00).

- ***Pressurized water reactor (PWR) primary system:*** Although the primary pressure boundary piping of PWRs has generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry, SCC has occurred in safety injection lines (NRC IN 97-19 and 84-18), charging pump casing cladding (NRC IN 80-38 and 94-63), instrument nozzles in safety injection tanks (NRC IN 91-05), control rod drive seal housing (NRC Inspection Report 50-255/99012), and safety-related SS piping systems that contain oxygenated, stagnant, or essentially stagnant borated coolant (NRC IN 97-19). Cracking has occurred in SS baffle former bolts in a number of foreign plants (NRC IN 98-11) and has been observed in plants in the United States. Cracking due to thermal and mechanical loading has occurred in high-pressure injection and safety injection piping (NRC IN 97-46 and NRC Bulletin 88-08). Through-wall circumferential cracking has been found in reactor pressure vessel head control rod drive penetration nozzles (NRC IN 2001-05). Evidence of reactor coolant leakage, together with crack-like indications, has been found in bottom-mounted instrumentation nozzles (NRC IN 2003-11 and IN 2003-11, Supplement 1). Cracking in pressurizer safety and relief line nozzles and in surge line nozzles has been detected (NRC IN 2004-11), and circumferential cracking in SS pressurizer heater sleeves has also been found (NRC IN 2006-27). Also, primary water SCC has been observed in steam generator drain bowl welds inspected as part of a licensee's Alloy 600/82/182 program (NRC IN 2005-02).

- ***PWR secondary system:*** Steam generator tubes have experienced outside diameter SCC, intergranular attack, wastage, and pitting (NRC IN 97-88). Carbon steel support plates in steam generators have experienced general corrosion. Steam generator shells have experienced pitting and SCC (NRC INs 82-37, 85-65, and 90-04).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE including research and development such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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XI.M2 WATER CHEMISTRY

Program Description

The main objective of this program is to mitigate 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 a treated water environment. The program includes periodic monitoring of the treated water in order to minimize loss of material or cracking.

The water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines contained in the Boiling Water Reactor Vessel and Internals Project (BWRVIP)-190 (Electric Power Research Institute [EPRI] 3002002623, "BWR Vessel and Internals Project: BWR Water Chemistry Guidelines," Revision 1.) The BWRVIP-190 has three sets of guidelines: (1) one for reactor water, (2) one for condensate and feedwater, and (3) one for control rod drive mechanism cooling water. The water chemistry program for pressurized water reactors (PWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines contained in EPRI 3002000505, "PWR Primary Water Chemistry Guidelines," Revision 7 and EPRI 3002010645, "PWR Secondary Water Chemistry Guidelines," Revision 8.

The water chemistry programs are generally effective in removing impurities from intermediate and high flow areas. The Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (GALL-SLR Report) identifies the circumstances in which the water chemistry program is to be augmented to manage the effects of aging for license renewal. For example, the water chemistry program may not be effective in low-flow or stagnant-flow areas. Accordingly, in certain cases, as identified in the GALL-SLR Report, the verification of the effectiveness of the chemistry control program is undertaken to provide reasonable assurance that significant degradation is not occurring and the component's intended function is maintained during the subsequent period of extended operation. For these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system.

Evaluation and Technical Basis

1 ***Scope of Program:*** The program includes components in the reactor coolant system, the engineered safety features, the auxiliary systems, and the steam and power conversion system. This program addresses the metallic components subject to aging management review that are exposed to a treated water environment controlled by the water chemistry program.

2 ***Preventive Actions:*** The program includes specifications for chemical species, impurities and additives, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to general, crevice, and pitting corrosion and cracking caused by SCC. For BWRs, maintaining high water purity reduces susceptibility to SCC, and chemical additive programs such as hydrogen water chemistry or noble metal chemical application also may be used. For PWRs, additives are used for reactivity control, to control pH and dose rates, and inhibit corrosion.

3 ***Parameters Monitored or Inspected:*** The concentrations of corrosive impurities listed in the EPRI water chemistry guidelines are monitored to mitigate loss of material, cracking, and reduction of heat transfer. Water quality also is maintained in accordance with the guidance.

Chemical species and water quality are monitored by in-process methods or through sampling. The chemical integrity of the samples is maintained and verified to provide reasonable assurance that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples.

4 ***Detection of Aging Effects:*** This is a mitigation program and does not provide for detection of any aging effects of concern for the components within its scope. The monitoring methods and frequency of water chemistry sampling and testing are performed in accordance with the EPRI water chemistry guidelines and based on plant operating conditions. The main objective of this program is to mitigate the loss of material due to corrosion and cracking due to SCC in components exposed to a treated water environment.

5 ***Monitoring and Trending:*** Chemistry parameter data are recorded, evaluated, and trended in accordance with the EPRI water chemistry guidelines.

6 ***Acceptance Criteria:*** Maximum levels for various chemical parameters are maintained within the system-specific limits as indicated by the limits specified in the corresponding EPRI water chemistry guidelines.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (*10* CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50 (TN249), Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Any evidence of aging effects or unacceptable water chemistry results is evaluated, the cause identified, and the condition corrected. When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range (or to change the operational mode of the plant) within the time period specified in the EPRI water chemistry guidelines. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling or other appropriate actions are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants, such as chlorides, fluorides, sulfates, and dissolved oxygen, to within the acceptable ranges.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The EPRI guideline documents have been developed based on plant experience and have been shown to be effective over time with their widespread use. The specific examples of operating experience (OE) are as follows:

- **BWR:** Intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic stainless steels (SSs) and nickel-based alloys. Significant cracking has occurred in recirculation, core spray, residual heat removal systems, and reactor water cleanup system piping welds. IGSCC has also occurred in a number of vessel internal components, including the core shroud, access hole cover, top guide, and core spray spargers (U.S. Nuclear Regulatory Commission [NRC] Inspection and Enforcement Bulletin [IEB] 80-13, NRC Information Notice [IN] 95-17, NRC Generic Letter [GL] 94-03, and NUREG–1544). No occurrence of SCC in piping and other components in standby liquid control systems exposed to sodium pentaborate solution has ever been reported (NUREG/CR–6001).

- **PWR Primary System:** The potential for SCC-type mechanisms might normally occur because of inadvertent introduction of contaminants into the primary coolant system, including contaminants introduced from the free surface of the spent fuel pool (which can be a natural collector of airborne contaminants) or the introduction of oxygen during plant cooldowns (NRC IN 84–18). Ingress of demineralizer resins into the primary system has caused IGSCC of Alloy 600 vessel head penetrations (NRC IN 96-11, NRC GL 97-01). Inadvertent introduction of sodium thiosulfate into the primary system has caused IGSCC of steam generator tubes. SCC has occurred in safety injection lines (NRC INs 97-19 and 84-18), charging pump casing cladding (NRC INs 80-38 and 94-63), instrument nozzles in safety injection tanks (NRC IN 91-05), and safety-related SS piping systems that contain oxygenated, stagnant, or essentially stagnant borated coolant (NRC IN 97-19). Steam generator tubes and plugs and Alloy 600 penetrations have experienced primary water SCC (NRC INs 89-33, 94-87, 97-88, 90-10, and 96-11; NRC Bulletin 89-01 and its two supplements). IGSCC-induced circumferential cracking has occurred in PWR pressurizer heater sleeves (NRC IN 2006-27).

- **PWR Secondary System:** Steam generator tubes have experienced outside diameter SCC, intergranular attack, wastage, and pitting (NRC IN 97-88, NRC GL 95-05). Carbon steel support plates in steam generators have experienced general corrosion. The steam generator shell has experienced pitting and SCC (NRC INs 82-37, 85-65, and 90-04). Extensive buildup of deposits at steam generator tube support holes can result in flow-induced vibrations and tube cracking (NRC IN 2007-37).

Such OE has provided feedback to revisions of the EPRI water chemistry guideline documents.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

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XI.M3 REACTOR HEAD CLOSURE STUD BOLTING

Program Description

This program includes (1) inservice inspection (ISI) in accordance with the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code),[1] Section XI, Subsection IWB, Table IWB 2500-1; and (2) preventive measures to mitigate cracking. The program also relies on recommendations delineated in U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.65, Revision 1.

Evaluation and Technical Basis

1 ***Scope of Program:*** The program manages the aging effects of cracking due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) and loss of material due to wear or corrosion for reactor vessel closure stud bolting (studs, washers, bushings, nuts, and threads in flange) for both boiling water reactors (BWRs) and pressurized water reactors.

2 ***Preventive Actions:*** Preventive measures may include the following:

a. Avoiding the use of metal-plated stud bolting to prevent degradation due to corrosion or hydrogen embrittlement.

b. Using manganese phosphate or other acceptable surface treatments.

c. Using stable lubricants. Of particular note, use of molybdenum disulfide (MoS_2) as a lubricant has been shown to be a potential contributor to SCC, so it should not be used.

d. Using bolting material for closure studs that has an actual measured yield strength less than 150 kilo-pounds per square inch (ksi) (1,034 megapascals [MPa]), or an ultimate tensile strength not exceeding 170 ksi (1,172 MPa).

Implementation of these mitigation measures can reduce the potential for SCC or IGSCC to occur, thus making this program effective.

3 ***Parameters Monitored or Inspected:*** The ASME Code Section XI ISI program detects and sizes cracks, detects loss of material, and detects coolant leakage by following the examination and inspection requirements specified in Table IWB-2500-1.

4 ***Detection of Aging Effects:*** The extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity, detect aging effects, and repair or replace components before the loss of intended function of the component. Inspection can reveal cracking, loss of material due to corrosion or wear, and leakage of coolant.

The program uses visual, surface, and volumetric examinations in accordance with the general requirements of Subsection IWA-2000. Surface examination uses magnetic particle or liquid penetrant examinations to indicate the presence of surface discontinuities and flaws. Volumetric examination uses radiographic or ultrasonic examinations to indicate the presence of discontinuities or flaws throughout the volume of material. Visual VT-2 examination detects evidence of leakage from pressure-retaining components, as required during the system pressure test.

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[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this aging management program.

Components are examined and tested in accordance with ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1, for pressure-retaining bolting greater than 2 inches in diameter. Examination Category B-P for all pressure-retaining components specifies visual VT-2 examination of all pressure-retaining boundary components during the system leakage test. Table IWB-2500-1 specifies the extent and frequency of the inspection and examination methods, and IWB-2400 specifies the schedule of the inspection.

5 ***Monitoring and Trending:*** The inspection schedule of IWB-2400 and the extent and frequency of IWB-2500-1 provide for timely detection of cracks, loss of material, and leakage.

6 ***Acceptance Criteria:*** Any indication or relevant condition of degradation in closure stud bolting is evaluated in accordance with IWB-3100 by comparing ISI results with the acceptance standards of IWB-3400 and IWB-3500.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed through implementation of the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50 (TN249), Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Repair and replacement are performed in accordance with the requirements of IWA-4000. The guidance for use of stud materials resistant to SCC or IGSCC is described in the "preventive actions" program element.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** SCC has occurred in BWR pressure vessel head studs (Stoller 1991). The AMP has provisions regarding inspection techniques and evaluation, material specifications, corrosion prevention, and other aspects of reactor pressure vessel head stud cracking. Implementation of the program provides reasonable assurance that the effects of cracking due to SCC or IGSCC and loss of material due to wear are adequately managed so that the intended functions of the reactor head closure studs and bolts are maintained consistent with the current licensing basis for the subsequent period of extended operation. Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred because of boric acid corrosion, SCC, and fatigue loading (NRC Inspection and Enforcement Bulletin 82-02, NRC Generic Letter 91-17).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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[2] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

XI.M4 BWR VESSEL ID ATTACHMENT WELDS

Program Description

This program is a condition monitoring program for detecting cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), and cyclical loading mechanisms in the reactor vessel inside diameter (ID) attachment welds of boiling water reactors (BWRs). The program includes inspection and flaw evaluation in accordance with the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, and the guidance in “BWR Vessel and Internals Project, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines” (Boiling Water Reactor Vessel and Internals Project [BWRVIP]-48-A) to provide reasonable assurance of the long-term integrity and safe operation of BWR vessel ID attachment welds.

The guidance in BWRVIP-48-A includes inspection recommendations and evaluation methodologies for certain attachment welds between the vessel wall and the brackets that attach components to the vessel. In some cases, the attachment is a weld attached directly to the vessel wall; in other cases, the attachment includes a weld build-up pad on the vessel wall. The BWRVIP-48-A report includes information about the geometry of the vessel ID attachments; evaluates susceptible locations and the safety consequence of failure; provides recommendations regarding the method, extent, and frequency of augmented examinations; and discusses acceptable methods for evaluating the significance of structural integrity indications detected during examinations.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages the effects of cracking caused by SCC, IGSCC, or cyclical loading mechanisms for the BWR vessel ID attachment welds that are covered by BWRVIP-48-A. The program is an augmented inservice inspection (ISI) program that uses the inspection and flaw evaluation criteria in BWRVIP-48-A to detect cracking and monitor the effects of cracking on the intended functions of these components.

2 ***Preventive Actions:*** This program is a condition monitoring program and has no preventive actions. To mitigate SCC and IGSCC, reactor coolant water chemistry is monitored and controlled in accordance with activities that meet the guidelines in Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M2, “Water Chemistry.”

3 ***Parameters Monitored or Inspected:*** This program monitors for cracks caused by SCC, IGSCC, and cyclical loading mechanisms. Inspections performed in accordance with the guidance in BWRVIP-48-A and the requirements of the ASME Code, Section XI, Table IWB-2500-1, are used to interrogate the components for discontinuities that may indicate the presence of cracking.

4 ***Detection of Aging Effects:*** The extent and schedule of the inspections prescribed by BWRVIP-48-A and ASME Code, Section XI, are designed to maintain structural integrity, to discover aging effects, and to repair or replace the component before a loss of intended function. The vessel ID attachment welds are visually examined in accordance with the requirements of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-N-2. The inspection and evaluation guidelines of BWRVIP-48-A recommend more stringent inspections for certain attachment welds. The nondestructive examination techniques that are appropriate for the augmented examinations, including the uncertainties inherent in delivering and executing these techniques and applicable for inclusion in flaw evaluations, are included in BWRVIP-03.

5 ***Monitoring and Trending:*** Inspections scheduled in accordance with ASME Code, Section XI, Subarticle IWB-2400, and BWRVIP-48-A provide for the timely detection of cracking. If indications are detected, the scope of examination is expanded. Any indications are evaluated in accordance with ASME Code, Section XI, and the guidance in BWRVIP-48-A. Guidance for the evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels is provided in BWRVIP-14-A, BWRVIP-59-A, and BWRVIP-60-A, respectively.

6 ***Acceptance Criteria:*** The relevant acceptance criteria are provided in BWRVIP-48-A and ASME Code, Section XI, Subarticle IWB-3520.

7 ***Corrective Actions*****:** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulation* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Repair and replacement activities are conducted in accordance with the guidance in BWRVIP-52-A.

8 ***Confirmation Process*****:** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Cracking due to SCC, IGSCC, and cyclical loading has occurred in BWR components. The program guidelines are based on an evaluation of available information, including BWR inspection data and information about the causes of SCC, IGSCC, and cracking due to cyclical loading, to determine which attachment welds may be susceptible to cracking caused by any of these mechanisms. Implementation of this program provides reasonable assurance that cracking will be adequately managed and that the intended functions of the vessel ID attachments will be maintained consistent with the current licensing basis for the subsequent period of extended operation.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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_____. BWRVIP-48-A (EPRI 1009948), “BWR Vessel and Internals Project, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines.” Palo Alto, California: Electric Power Research Institute. November 2004.

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_____. BWRVIP-60-A (EPRI 1008871), “BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals.” Palo Alto, California: Electric Power Research Institute. June 2003.

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

XI.M5 DELETED

XI.M6 DELETED

XI.M7 BWR STRESS CORROSION CRACKING

Program Description

The program to manage intergranular stress corrosion cracking (IGSCC) in boiling water reactor (BWR) coolant pressure boundary piping made of stainless steel (SS) and nickel-based alloy components is delineated in NUREG–0313, Revision 2, and the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-01 and its Supplement 1. The material includes base metal and welds. The comprehensive program outlined in NUREG–0313, Revision 2 and NRC GL 88-01 describes improvements that, in combination, will reduce the susceptibility to IGSCC. The elements that cause IGSCC consist of a susceptible–material, a significant tensile stress, and an aggressive environment. Sensitization of nonstabilized austenitic SSs containing greater than 0.035 weight percent carbon involves precipitation of chromium carbides at the grain boundaries during certain fabrication or welding processes. The formation of carbides creates a chromium-depleted region that, in certain environments, is susceptible to stress corrosion cracking (SCC). Residual tensile stresses are introduced by fabrication processes, such as welding, cold work, surface grinding, and forming. High levels of dissolved oxygen or aggressive contaminants, such as sulfates or chlorides, accelerate the SCC processes. The program includes (1) preventive measures to mitigate IGSCC and (2) inspection and flaw evaluation to monitor IGSCC and its effects. The staff-approved Boiling Water Reactor Vessel and Internals Project (BWRVIP)-75-A report allows for modifications to the inspection extent and schedule described in the NRC GL 88-01 program.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program focuses on (1) managing and implementing countermeasures to mitigate IGSCC and (2) performing ISI to monitor IGSCC and its effects on the intended function of BWR piping components within the scope of license renewal. The program is applicable to all BWR piping and piping welds made of austenitic SS and nickel alloy that are 4 inches or larger in nominal diameter containing reactor coolant at a temperature above 93 °C (Celsius; 200 °F [Fahrenheit]) during power operation, regardless of code classification. The program also applies to pump casings, valve bodies, and reactor vessel attachments and appurtenances, such as head spray and vent components. Control rod drive return line nozzle caps and associated welds (previously addressed in Generic Aging Lessons Learned [GALL] Report, Revision 2, AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle") may be included in the scope of the program. NUREG–0313, Revision 2 and NRC GL 88-01, respectively, describe the technical basis and staff guidance regarding mitigation of IGSCC in BWRs. Attachment A of NRC GL 88-01 delineates the staff-approved positions regarding materials, processes, water chemistry, weld overlay reinforcement, partial replacement, stress improvement of cracked welds, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting requirements.

2 ***Preventive Actions:*** The BWR SCC program is primarily a condition monitoring program that also relies on countermeasures. Maintaining high water purity reduces susceptibility to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the Water Chemistry program. The program description, evaluation, and technical basis of water chemistry are addressed through implementation of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M2, "Water Chemistry." In addition, NUREG–0313, Revision 2 and GL 88-01 delineate the guidance for selection of resistant materials and processes that provide resistance to IGSCC such as solution heat treatment and stress improvement processes.

3 ***Parameters Monitored or Inspected:*** The program detects and sizes cracks and detects leakage by using the examination and inspection guidelines delineated in NUREG–0313, Revision 2, and NRC GL 88-01.

4 ***Detection of Aging Effects:*** The extent, method, and schedule of the inspection and test techniques delineated in NRC GL 88-01 are designed to maintain structural integrity, detect and mitigate degradation, and repair or replace components before the loss of intended function of the component. Modifications of the extent and schedule of inspection in NRC GL 88-01 are allowed in accordance with the inspection guidance in approved BWRVIP-75-A. The potential for stagnant flow conditions such as dead legs is considered when selecting inspection locations. The program identifies these locations. Prior to crediting hydrogen water chemistry to modify the extent and frequency of inspections in accordance with BWRVIP-75-A, the applicant should meet the conditions described in the staff's safety evaluations regarding BWRVIP-62-A. The program uses volumetric examinations to detect IGSCC. Inspection can reveal cracking and leakage of coolant. The extent and frequency of inspection recommended by the program are based on the condition of each weld (e.g., whether the weldments were made from IGSCC-resistant material, whether a stress improvement process was applied to a weldment to reduce residual stresses, and how the weld was repaired, if it had been cracked).

5 ***Monitoring and Trending:*** The extent of and schedule for inspection, in accordance with the recommendations of NRC GL 88-01 or approved BWRVIP-75-A guidelines, provide for timely detection of cracks and leakage of coolant. Indications of cracking are evaluated and trended in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, IWA-3000.

Applicable and approved BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, and BWRVIP-62-A reports provide guidelines for evaluation of crack growth in SSs, nickel alloys, and low-alloy steels. An applicant may use BWRVIP-61 guidelines for BWR vessel and internals induction heating stress improvement effectiveness on crack growth in operating plants.

6 ***Acceptance Criteria:*** Any cracking is evaluated in accordance with ASME Code, Section XI, IWA-3000 by comparing inspection results with the acceptance standards of ASME Code, Section XI, IWB-3000, IWC-3000 and IWD-3000 for Class 1, 2 and 3 components, respectively.

7 ***Corrective Actions*****:** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50 (TN249), Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

The guidance for weld overlay repair and stress improvement or replacement is provided in NRC GL 88-01. Corrective actions are performed in accordance with IWA-4000.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Intergranular SCC has occurred in small- and large-diameter BWR piping made of austenitic SS and nickel-based alloys. Cracking has occurred in recirculation, core spray, residual heat removal, control rod drive return line penetrations, and reactor water cleanup system piping welds (NRC GL 88-01 and NRC Information Notices 82-39, 84-41, and 2004-08). The comprehensive program outlined in NRC GL 88-01, NUREG–0313, Revision 2, and in the staff-approved BWRVIP-75-A report addresses mitigating measures for SCC or IGSCC (e.g., susceptible material, significant tensile stress, and an aggressive environment). The GL 88-01 program, with or without the modifications allowed by the staff-approved BWRVIP-75-A report, has been effective in managing IGSCC in BWR coolant pressure-retaining components and will adequately manage IGSCC degradation.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

ASME. ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” New York, New York: The American Society of Mechanical Engineers. 2008. [1]

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EPRI. BWRVIP-14-A (EPRI 1016569), “BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Stainless Steel RPV Internals.” Palo Alto, California: Electric Power Research Institute. September 2008.

_____. BWRVIP-59-A, (EPRI 1014874), “BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals.” Palo Alto, California: Electric Power Research Institute. May 2007.

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

_____. BWRVIP-60-A (EPRI 108871), “BWR Vessel and Internals Project, Evaluation of Stress Corrosion Crack Growth in Low Alloy Steel Vessel Materials in the BWR Environment.” Palo Alto, California: Electric Power Research Institute. June 2003.

_____. BWRVIP-61 (EPRI 112076), “BWR Vessel and Internals Induction Heating Stress Improvement Effectiveness on Crack Growth in Operating Reactors.” Palo Alto, California: Electric Power Research Institute. January 1999.

_____. BWRVIP-62-A (EPRI-1021006), “BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection.” Palo Alto, California: Electric Power Research Institute. November 2010.

_____. BWRVIP-75-A (EPRI 1012621), “BWR Vessel and Internals Project, Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG–0313).” Palo Alto, California: Electric Power Research Institute. October 2005.

NRC. Generic Letter 88-01, “NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping.” Washington, DC: U.S. Nuclear Regulatory Commission. January 25, 1988; Supplement 1, February 1992.

_____. Information Notice 04-08, “Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds.” Washington, DC: U.S. Nuclear Regulatory Commission. April 2004.

_____. Information Notice 82-39, “Service Degradation of Thick Wall Stainless Steel Recirculation System Piping at a BWR Plant.” Washington, DC: U.S. Nuclear Regulatory Commission. September 1982.

_____. Information Notice 84-41, “IGSCC in BWR Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1984.

_____. NUREG–0313, “Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping.” Revision 2. Washington DC: U.S. Nuclear Regulatory Commission. 1988.

XI.M8 BWR PENETRATIONS

Program Description

This program for boiling water reactor (BWR) vessel instrumentation penetrations, control rod drive (CRD) housing and incore-monitoring housing (ICMH) penetrations, and standby liquid control (SLC) nozzles/Core ΔP nozzles includes inspection and flaw evaluation in conformance with the guidelines of staff-approved Boiling Water Reactor Vessel and Internals Project (BWRVIP) Topical Reports BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A. The program manages cracking due to cyclic loading, stress corrosion cracking (SCC), and intergranular stress corrosion cracking (IGSCC) for these BWR vessel penetrations and nozzles. The inspection and evaluation guidelines of BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A contain generic guidelines intended to present appropriate inspection recommendations to assure safety function integrity. The guidelines of BWRVIP-49-A provide information about the type of instrument penetration, evaluate their susceptibility and consequences of failure, and define the inspection strategy to assure safe operation. The guidelines of BWRVIP-47-A provide information about components located in the lower plenum region of BWRs, evaluate their susceptibility and consequences of failure, and define the inspection strategy to assure safe operation. The guidelines of BWRVIP-27-A are applicable to plants in which the SLC system injects sodium pentaborate into the bottom head region of the vessel (in most plants, as a pipe within a pipe of the core plate ΔP monitoring system). The BWRVIP-27-A guidelines address the region where the ΔP and SLC nozzle or housing penetrates the vessel bottom head and include the safe ends welded to the nozzle or housing. Guidelines for repair design criteria are provided in BWRVIP-57-A for instrumentation penetrations, in BWRVIP-55-A for CRD housing and ICMH penetrations, and in BWRVIP-53-A for the SLC line.

Although this is a condition monitoring program, control of water chemistry helps prevent SCC and IGSCC. The Water Chemistry program for BWRs relies on monitoring and control of reactor water chemistry based on industry guidelines, such as BWRVIP-190 (EPRI 1016579) or later revisions. BWRVIP-190 has three sets of guidelines: (1) one for primary water, (2) one for condensate and feedwater, and (3) one for CRD mechanism cooling water. Adequate aging management activities for these components provide reasonable assurance of the long-term integrity and safe operation of BWR vessel instrumentation nozzles, CRD housing and ICMH penetrations, and SLC nozzles/Core ΔP nozzles.

Evaluation and Technical Basis

1. ***Scope of Program:*** The scope of this program is applicable to BWR instrumentation penetrations, CRD housing and ICMH penetrations, and BWR SLC nozzles/Core ΔP nozzles. The program manages cracking due to cyclic loading or SCC and IGSCC using inspection and flaw evaluation in accordance with the guidelines of staff-approved BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A.

2. ***Preventive Actions:*** This program is a condition monitoring program and has no preventive actions. However, maintaining high water purity reduces susceptibility to SCC or IGSCC. The program description, evaluation, and technical basis of water chemistry are presented in the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M2, "Water Chemistry."

3. ***Parameters Monitored or Inspected:*** The program manages the effects of cracking due to SCC/IGSCC on the intended function of the BWR instrumentation nozzles, CRD housing and ICMH penetrations, and BWR SLC nozzles/Core ΔP nozzles. The program monitors for

evidence of surface-breaking linear discontinuities if a visual inspection technique is used or for relevant flaw signals if a volumetric ultrasonic testing (UT) method is used. In addition, the program includes visual examination to confirm the absence of leakage.

4 ***Detection of Aging Effects:*** The inspection guidelines of BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A, along with the existing inspection requirements in American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, Table IWB-2500-1, are sufficient to monitor for indications of cracking in BWR instrumentation nozzles, CRD housing and ICMH penetrations, and BWR SLC nozzles/Core ΔP nozzles, and should continue to be followed for the subsequent period of extended operation. The extent of and schedule for the inspection and test techniques, prescribed by the staff-approved BWRVIP inspection guidelines and the ASME Code, Section XI program, are designed to maintain structural integrity, to detect aging effects, and to perform repair or replacement before the loss of intended function of the component.

Instrument penetrations, CRD housing and ICMH penetrations, and SLC system nozzles or housings are inspected in accordance with the staff-approved BWRVIP inspection guidelines and the requirements in the ASME Code, Section XI. These examination categories include volumetric examination methods (UT or radiography testing), surface examination methods (liquid penetrant testing or magnetic particle testing), and VT-2 visual examination methods.

5 ***Monitoring and Trending:*** Inspections scheduled in accordance with ASME Code, Section XI, IWB-2400 and approved BWRVIP-49-A, BWRVIP-47-A, or BWRVIP-27-A provide for timely detection of cracks. The scope of examination and reinspection is expanded beyond the baseline inspection if flaws are detected. Any indication detected is evaluated in accordance with ASME Code, Section XI or other acceptable flaw evaluation criteria, such as the staff-approved BWRVIP-49-A, BWRVIP-47-A, or BWRVIP-27-A guidelines. Applicable and approved BWRVIP-14-A, BWRVIP-59-A, and BWRVIP-60-A documents provide additional guidelines for the evaluation of crack growth in stainless steels (SSs), nickel alloys, and low-alloy steels, respectively.

6 ***Acceptance Criteria:*** Acceptance criteria are given in BWRVIP-49-A for instrumentation nozzles, in BWRVIP-47-A for CRD housing and ICMH penetrations, and in BWRVIP-27-A for BWR SLC nozzles/Core ΔP nozzles.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Corrective actions include repair and replacement procedures in staff-approved BWRVIP-57-A, BWRVIP-55-A, BWRVIP-58-A, and BWRVIP-53-A that are equivalent to those required in ASME Code, Section XI. Guidelines for repair design criteria are provided in BWRVIP-57-A for instrumentation penetrations, in BWRVIP-55-A for CRD housing and ICMH penetrations, and in BWRVIP-53-A for SLC line. BWRVIP-58-A provides guidelines for internal access weld repair for CRD penetrations.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how

an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

The staff finds that licensee implementation of the guidelines in BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A, as modified, provides an acceptable level of quality for inspection and flaw evaluation of the safety-related components addressed in accordance with the 10 CFR Part 50, Appendix B confirmation process and administrative controls.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Cracking due to SCC or IGSCC has occurred in BWR components made of austenitic SSs and nickel alloys. The program guidelines are based on an evaluation of available information, including BWR inspection data and information about the elements that cause IGSCC, to determine which locations may be susceptible to cracking. Implementation of the program provides reasonable assurance that cracking will be adequately managed so the intended functions of the instrument penetrations and SLC system nozzles or housings will be maintained consistent with the current licensing basis for the subsequent period of extended operation.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

ASME. ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” New York, New York: The American Society of Mechanical Engineers. 2008.[1]

EPRI. BWRVIP-14-A (EPRI 1016569), “BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Stainless Steel RPV Internals.” Palo Alto, California: Electric Power Research Institute. September 2008.

_____. BWRVIP-27-A (EPRI 1007279), “BWR Vessel and Internals Project, BWR Standby Liquid Control System/Core Plate ∆P Inspection and Flaw Evaluation Guidelines.” Palo Alto, California: Electric Power Research Institute. August 2003.

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

_____. BWRVIP-47-A (EPRI 1009947), “BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines.” Palo Alto, California: Electric Power Research Institute. November 2004.

_____. BWRVIP-49-A (EPRI 1006602), “BWR Vessel and Internals Project, Instrument Penetration Inspection and Flaw Evaluation Guidelines.” Palo Alto, California: Electric Power Research Institute. 2002.

_____. BWRVIP-53-A (EPRI 1012120), “BWR Vessel and Internals Project, Standby Liquid Control Line Repair Design Criteria.” Palo Alto, California: Electric Power Research Institute. September 2005.

_____. BWRVIP-55-A (EPRI 1012117), “BWR Vessel and Internals Project, Lower Plenum Repair Design Criteria.” Palo Alto, California: Electric Power Research Institute. September 2005.

_____. BWRVIP-57-A (EPRI 1012111), “BWR Vessel and Internals Project, Instrument Penetration Repair Design Criteria.” Palo Alto, California: Electric Power Research Institute. September 2005.

_____. BWRVIP-58-A (EPRI 1012618), “BWR Vessel and Internals Project, CRD Internal Access Weld Repair.” Palo Alto, California: Electric Power Research Institute. October 2005.

_____. BWRVIP-59-A (EPRI 1014874), “BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals.” Palo Alto, California: Electric Power Research Institute. May 2007.

_____. BWRVIP-60-A (EPRI 1008871), “BWR Vessel and Internals Project, Evaluation of Stress Corrosion Crack Growth in Low Alloy Steel Vessel Materials in the BWR Environment.” Palo Alto, California: Electric Power Research Institute. June 2003.

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XI.M9 BWR VESSEL INTERNALS

Program Description

This program includes inspection and flaw evaluations in conformance with the guidelines of applicable and staff-approved Boiling Water Reactor Vessel and Internals Project (BWRVIP) documents to provide reasonable assurance of the long-term integrity and safe operation of boiling water reactor (BWR) vessel internal components. The program manages the effects of cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or irradiation-assisted stress corrosion cracking (IASCC); cracking due to cyclic loading (including flow-induced vibration); loss of material due to wear; loss of fracture toughness due to neutron or thermal embrittlement; and loss of preload due to thermal or irradiation-enhanced stress relaxation.

The BWRVIP documents provide generic guidelines intended to present the applicable inspection recommendations to assure safety function integrity of the subject safety-related reactor pressure vessel internal components. The guidelines provide information about component description and function; evaluate susceptible locations and safety consequences of failure; provide recommendations for methods, extent, and frequency of inspection; discuss acceptable methods for evaluating the structural integrity significance of flaws detected during these examinations; and recommend repair and replacement procedures.

In addition, this program provides screening criteria to determine the susceptibility of cast austenitic stainless steel (CASS) components to thermal aging on the basis of casting method, molybdenum content, and percent ferrite, in accordance with the criteria set forth in the May 19, 2000 letter from Christopher Grimes, U.S. Nuclear Regulatory Commission (NRC), to Mr. Douglas Walters, Nuclear Energy Institute (NEI). The susceptibility to thermal aging embrittlement of CASS components is determined in terms of casting method, molybdenum content, and ferrite content. For low-molybdenum content steels (SA-351 Grades CF3, CF3A, CF8, CF8A, or other steels with ≤0.5 percent molybdenum), only static-cast steels with >20 percent ferrite are potentially susceptible to thermal embrittlement. Static-cast low-molybdenum steels with ≤20 percent ferrite and all centrifugal-cast low-molybdenum steels are not susceptible. For high-molybdenum content steels (SA-351 Grades CF3M, CF3MA, CF8M or other steels with 2.0 to 3.0 percent molybdenum), static-cast steels with >14 percent ferrite and centrifugal-cast steels with >20 percent ferrite are potentially susceptible to thermal embrittlement. Static-cast high-molybdenum steels with ≤14 percent ferrite and centrifugal-cast high-molybdenum steels with ≤20 percent ferrite are not susceptible. In the susceptibility screening method, ferrite content is calculated by using the Hull's equivalent factors (described in NUREG/CR–4513, Revision 1) or a staff-approved method for calculating delta ferrite in CASS materials. A subsequent license renewal (SLR) applicant may use alternative staff-approved screening criteria when determining the susceptibility of CASS to neutron and thermal embrittlement (e.g., screening criteria approved in the June 22, 2016, safety evaluation regarding BWRVIP-234).

The screening criteria are applicable to all cast stainless steel (SS) primary pressure boundary and reactor vessel internal components with service conditions above 250 °C (Celsius; 482 °F [Fahrenheit]). The screening criteria for susceptibility to thermal aging embrittlement are not applicable to niobium-containing steels; such steels require evaluation on a case-by-case basis. For "potentially susceptible" components, the program considers loss of fracture toughness due to neutron embrittlement or thermal aging embrittlement.

This aging management program (AMP) addresses aging degradation of nickel alloy and SS that are used in BWR vessel internal components. When exposed to the BWR vessel environment, these materials can experience neutron embrittlement and a decrease in fracture toughness. CASS, precipitation-hardened (PH) martensitic SS (e.g., 15-5 and 17-4 PH steel) and martensitic SS (e.g., 403, 410, 431 steel) are also susceptible to thermal embrittlement.The effects of thermal or neutron embrittlement can cause failure of these materials in vessel internal components. In addition, nickel alloy in a BWR environment is susceptible to IGSCC.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program is focused on managing the effects of cracking due to SCC, IGSCC, or IASCC; cracking due to cyclic loading (including flow-induced vibration); and loss of material due to wear. The program also manages loss of fracture toughness due to neutron or thermal embrittlement and loss of preload due to thermal or irradiation-enhanced stress relaxation. The program applies to wrought and cast reactor vessel internal components. The program contains inservice inspection (ISI) to monitor the effects of cracking on the intended function of the components; uses staff-approved BWRVIP reports as the basis for inspection, evaluation, repair and/or replacement, as needed; and evaluates the susceptibility of nickel alloy, CASS, precipitation-hardened (PH) martensitic SS (e.g., 15-5 and 17-4 PH steel), martensitic SS (e.g., 403, 410, 431 steel) and other SS (e.g., 304 steel) components to neutron or thermal embrittlement.

The scope of the program includes the following BWR reactor vessel (RV) and RV internal components, for which the corresponding staff-approved BWRVIP guidelines apply:

- *Core shroud:* BWRVIP-76, Revision 1-A provides guidelines for inspection and evaluation; BWRVIP-02, Revision 2-A provides guidelines for repair design criteria. BWRVIP-100, Revision 1-A describes flaw evaluation methodologies and fracture toughness data for SS core shroud exposed to neutron irradiation. However, more recent data from material harvesting programs suggest that the fracture mode of irradiated stainless steel weld metal transitions to brittle fracture at a neutron fluence of $5×10^{20}$ n/cm^2 [E>1 MeV], rather than $1×10^{21}$ n/cm^2 [E>1 MeV] (see ML21153A003). Accordingly, SLR applicants should account for the latest data from BWRVIP research programs in their vessel internals inspection program.

- *Core plate:* BWRVIP-25, Revision 1-A provides guidelines for inspection and evaluation; BWRVIP-50-A provides guidelines for repair design criteria.

- *Core spray:* BWRVIP-18, Revision 2-A provides guidelines for inspection and evaluation; BWRVIP-16-A and BWRVIP-19-A provide guidelines for replacement and repair design criteria, respectively.

- *Shroud support:* BWRVIP-38 provides guidelines for inspection and evaluation; BWRVIP-52-A provides guidelines for repair design criteria.

- *Jet pump assembly:* BWRVIP-41, Revision 4-A and BWRVIP-138, Revision 1-A, provide guidelines for inspection and evaluation; BWRVIP-51-A provides guidelines for repair design criteria.

- *Low-pressure coolant injection coupling:* BWRVIP-42, Revision 1-A provides guidelines for inspection and evaluation; BWRVIP-56-A provides guidelines for repair design criteria.

- *Top guide:* BWRVIP-26-A and BWRVIP-183-A provide guidelines for inspection and evaluation; BWRVIP-50-A provides guidelines for repair design criteria. The program includes inspection of 10 percent of the top guide locations using enhanced visual technique (EVT-1) or ultrasonic testing every 12 years with at least 5 percent inspected within the first 6 years of each 12-year interval.

Reinspection Criteria:

- BWR/2-5 – Inspect 10 percent of the grid beam cells containing control rod drives/blades every 12 years with at least 5 percent to be performed within 6 years.
- BWR/6 – Inspect the rim areas containing the weld and heat affected zone from the top surface of the top guide and two cells in the same plane/axis as the weld every 6 years.

The top guide inspection locations are those that have high neutron fluence exceeding the IASCC threshold (i.e., $\geq 5\times10^{20}$ n/cm^2 for E>1 MeV). The extent of the examination and its frequency will be based on a 10 percent sample of the total population, which includes all grid beam and beam-to-beam crevice slots.

- *Control rod drive housing and lower plenum components (reactor vessel internal components):* BWRVIP-47-A provides guidelines for inspection and evaluation; BWRVIP-55-A provides guidelines for repair design criteria.
- *Steam dryer:* BWRVIP-139,Revision 1-A provides guidelines for inspection and evaluation for the steam dryer components; BWRVIP-181-A provides guidelines for repair design criteria.

In addition, BWRVIP-180 provides guidelines for inspection and flaw evaluation of access hole covers and BWRVIP-217 provides guidelines for repair design criteria for these components.

BWRVIP-315 provides a review of how existing BWRVIP AMPs may be affected by operations beyond 60 years. The work in BWRVIP-315 may lead to future updates of existing BWRVIP guidance documents and future NRC reviews. SLR applicants are responsible for accounting for the planned updates described in BWRVIP-315. SLR applicants should address limitations and applicant action items imposed by NRC safety evaluations of BWRVIP documents, including BWRVIP-315.

2 ***Preventive Actions:*** The BWRVIP is a condition monitoring program and has no preventive actions. Maintaining high water purity reduces susceptibility to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the Water Chemistry program. The program description, evaluation, and technical basis of water chemistry are presented in Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M2, “Water Chemistry.”

3 ***Parameters Monitored or Inspected:*** This program manages the effects of aging on the intended function of the component by inspecting for cracking and loss of material in accordance with the guidelines of applicable and staff-approved BWRVIP documents and the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, Table IWB 2500-1.

Loss of fracture toughness due to neutron embrittlement in CASS materials can occur with a neutron fluence greater than 1×10^{17} n/cm^2 (E>1 MeV). Loss of fracture toughness of CASS material due to thermal embrittlement is dependent on the material’s casting method, molybdenum content, and ferrite content in accordance with the criteria set forth in the May 19, 2000, letter from Christopher Grimes, NRC, to Mr. Douglas Walters, NEI. A SLR applicant may use alternative staff-approved screening criteria when determining the susceptibility of CASS to neutron and thermal embrittlement (e.g., screening criteria approved in the June 22, 2016, safety evaluation regarding BWRVIP-234). This program does not directly monitor for loss of fracture toughness that is induced by thermal aging or neutron irradiation embrittlement. The impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components.

Loss of fracture toughness due to neutron or thermal embrittlement cannot be identified by typical ISI activities. However, by performing visual or other inspections, applicants can identify cracks that could lead to failure of a potentially embrittled component prior to component failure. Applicants can thus indirectly manage the effects of embrittlement in the nickel alloy and SS components by identifying aging degradation (i.e., cracks), implementing early corrective actions, and monitoring and trending age-related degradation.

This program also manages loss of preload due to thermal or irradiation-enhanced stress relaxation for core plate rim hold-down bolts and jet pump assembly hold-down beam bolts by performing visual inspections or stress analyses for adequate structural integrity.

4 ***Detection of Aging Effects:*** The extent of and schedule for the inspection and test techniques prescribed by the applicable and staff-approved BWRVIP guidelines are designed to maintain structural integrity, detect aging effects, and repair or replace components before the loss of intended function of BWR vessel internals. Vessel internal components are inspected in accordance with the requirements of ASME Code Section XI, Subsection IWB, Table IWB-2500-1, Examination Category B-N-2 for core support structures, and Examination Category B-N-1 for reactor vessel internal components. This inspection specifies visual VT-3 examination to determine the general mechanical and structural condition of the component supports by (1) verifying parameters, such as clearances, settings, and physical displacements; and (2) detecting discontinuities and imperfections, such as loss of integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion. BWRVIP program requirements provide for inspection of BWR internals to manage loss of material and cracking using appropriate examination techniques, such as visual examinations (e.g., EVT-1, VT-1) and volumetric examinations (e.g., ultrasonic testing).

The applicable and staff-approved BWRVIP guidelines recommend more stringent inspections, such as EVT-1 examinations or ultrasonic methods of volumetric inspection, for certain selected components and locations. The nondestructive examination (NDE) techniques appropriate for inspection of BWR vessel internals, including the uncertainties inherent in delivering and executing NDE techniques in a BWR, are included in BWRVIP-03, Revision 19.

Loss of fracture toughness due to neutron or thermal embrittlement is indirectly managed by performing periodic visual inspections capable of detecting cracks in the components. This program also determines whether supplemental inspections are necessary in addition to the existing BWRVIP examination guidelines to manage loss of fracture toughness for nickel alloy and SS internals, including welds. If supplemental inspections are determined to be necessary for BWR vessel internals, the program identifies the components to be inspected and performs supplemental inspections to adequately manage loss of fracture toughness due to neutron or thermal embrittlement. This evaluation for supplemental inspections is based on neutron fluence, thermal aging susceptibility, fracture toughness, and cracking susceptibility (i.e., applied stress, operating temperature, and environmental conditions). This program further determines whether supplemental inspections are necessary to manage cracking due to IASCC for nickel alloy and SS internals, including welds. This evaluation is based on neutron fluence and cracking susceptibility. If determined to be necessary, the program performs the supplemental inspections on the internal components identified in the evaluation.

The inspection technique is capable of detecting the critical flaw size with adequate margin. The critical flaw size is determined based on the service loading condition and service-degraded material properties. One example of a supplemental examination is VT-1 examination of ASME Code, Section XI, IWA-2210. The initial inspection is performed either prior to or within 5 years after entering the subsequent period of extended operation.

If cracking is detected after the initial inspection, the frequency of reinspection should be justified by the applicant based on fracture toughness properties appropriate for the condition of the component. The sample size is 100 percent of the accessible component population, excluding components that may be in compression during normal operations.

5 ***Monitoring and Trending:*** Inspections scheduled in accordance with the applicable and staff-approved BWRVIP guidelines provide timely detection of cracks. Each BWRVIP guideline recommends baseline inspections that are used as part of data collection toward trending. The BWRVIP guidelines provide recommendations for expanding the sample scope and reinspecting the components if flaws are detected. Any indication detected is evaluated in accordance with ASME Code, Section XI or the applicable BWRVIP guidelines. BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, BWRVIP-80-A, and BWRVIP-99-A documents provide additional guidelines for evaluation of crack growth in SSs and nickel alloys. Code Case N-889 provides an IASCC crack growth law for irradiated stainless steels. SLR applicants should apply this code case consistent with the latest revision of Regulatory Guide 1.147 incorporated by reference in 10 CFR 50.55a.

Inspections scheduled in accordance with ASME Code, Section XI, IWB-2400 and reliable examination methods provide timely detection of cracks. The fracture toughness of precipitation-hardened (PH) martensitic steels, martensitic SSs, and nickel alloys susceptible to thermal or neutron embrittlement need to be assessed on a case-by-case basis.

6 ***Acceptance Criteria:*** Acceptance criteria are given in the applicable staff-approved BWRVIP documents and ASME Code, Section XI. Flaws detected in the reactor vessel internals are evaluated in accordance with the procedures in the applicable staff-approved BWRVIP documents and ASME Code, Section XI.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Repair and replacement procedures are equivalent to the requirements in ASME Code Section XI. Repair and replacement is performed in conformance with applicable staff-approved BWRVIP guidelines. Guidelines for performing weld repairs to irradiated internals are described in BWRVIP-97-A. In addition, for core shroud repairs or other IGSCC repairs, the program maintains operating tensile stresses below a threshold limit that mitigates IGSCC of X-750 material in accordance with the guidelines in BWRVIP-84, Revision 2-A. For top guides where cracking is observed, sample size and inspection frequencies are increased in accordance with the BWRVIP guidelines.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** There is documentation of cracking in both the circumferential and axial core shroud welds, and in shroud supports. Extensive cracking of circumferential core shroud welds has been documented in NRC Generic Letter (GL) 94-03 and extensive cracking in vertical core shroud welds has been documented in NRC Information Notice (IN) 97-17. It has affected shrouds fabricated from Type 304 and Type 304L SS, which is generally considered to be more resistant to SCC. Weld regions are most susceptible to SCC, although it is not clear whether this is due to sensitization, impurities associated with the welds, or the high residual stresses in the weld regions. This experience is reviewed in NRC GL 94-03 and NUREG–1544; some experiences with visual inspections are discussed in NRC IN 94-42. In addition, IASCC was observed in the core shroud beltline region and IGSCC was observed in core shroud tie rod upper supports made of X-750 alloy (BWRVIP-76-A).

Both circumferential (NRC IN 88-03) and radial cracking (NRC IN 92-57) have been observed in the shroud support access hole covers that are made from Alloy 600. Instances of cracking in core spray spargers have been reviewed in NRC Inspection and Enforcement Bulletin (IEB) 80-13, and cracking in core spray pipe has been reviewed in BWRVIP-18, Revision 1-A.

Cracking of the core plate has not been reported, but the creviced regions beneath the plate are difficult to inspect. BWRVIP-06, Revision 1-A and BWRVIP-25, Revision 1-A address the safety significance and inspection requirements for the core plate assembly. Only inspection of core plate bolts (for plants without retaining wedges) or inspection of the retaining wedges is required. NRC IN 95-17 discusses cracking in top guides of United States and overseas BWRs. Related experience in other components is reviewed in NRC GL 94-03 and NUREG–1544. Cracking has also been observed in the top guide of a Swedish BWR. More recently, cracking was observed at the top guide grid to top guide rim cross-beam connection at a U.S. plant. The cause was attributed to IGSCC related to fabrication (see ML18142A387).

Instances of cracking have occurred in the jet pump assembly (NRC IEB 80-07), hold-down beam (NRC IN 93-101), and jet pump riser pipe elbows (NRC IN 97-02). Cracking of dry tubes has been observed at 14 or more BWRs. The cracking is intergranular and has been observed in dry tubes without apparent sensitization, suggesting that IASCC may also play a role in the cracking.

Two control rod drive mechanism lead screw male couplings were fractured in a pressurized water reactor (PWR), designed by Babcock & Wilcox, at Oconee Nuclear Station, Unit 3. The fracture was due to thermal embrittlement of 17-4 PH material (NRC IN 2007-02). While this occurred at a PWR, it also needs to be considered at BWRs.

IGSCC in the X-750 materials of a tie rod coupling and jet pump holddown beam was observed in a domestic plant.

The program guidelines outlined in applicable staff-approved BWRVIP documents are based on an evaluation of available information, including BWR inspection data and information about the elements that cause SCC, IGSCC, or IASCC, to determine which components may be susceptible to cracking. Implementation of the program provides reasonable assurance that cracking will be adequately managed so the intended functions of the vessel internal components will be maintained consistent with the current licensing basis for the subsequent period of extended operation.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

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XI.M10 BORIC ACID CORROSION

Program Description

This program relies, in part, on implementation of recommendations in the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-05 to identify, evaluate, and correct borated water leaks that could cause corrosion damage to reactor coolant pressure boundary components in pressurized water reactors. Potential improvements of boric acid corrosion programs have been identified because of operating experience (OE) with the cracking of certain nickel alloy pressure boundary components (NRC Regulatory Issue Summary 2003-013 and NUREG–1823).

Borated water leakage from piping and components that are outside the scope of the program established in response to NRC GL 88-05 may affect structures and components (SCs) that are subject to aging management review (AMR). Therefore, the scope of the monitoring and inspections of this program includes all components subject to an AMR that may be adversely affected by some form of borated water leakage. The scope of the evaluations, assessments, and corrective actions includes all observed leakage sources and the affected SCs.

Borated water leakage may be discovered through activities other than those established specifically to detect such leakage. Therefore, the program includes provisions for triggering evaluations and assessments when leakage is discovered by other activities. The effects of boric acid corrosion on reactor coolant pressure boundary materials in the vicinity of nickel alloy components are managed by Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) 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).”

The recommended approaches described in Section 7 of WCAP-15988-NP, Revision 2, “Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors,” provide an acceptable means of fulfilling the activities of this program.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program covers any SCs on which boric acid corrosion may occur (e.g., steel and copper alloy) and electrical components onto which borated reactor water may leak. The program includes provisions in response to the recommendations of NRC GL 88-05. NRC GL 88-05 elicits a program consisting of systematic measures to provide reasonable assurance that corrosion caused by leaking borated water does not lead to degradation of the leakage source or adjacent SCs, to provide assurance that the reactor coolant pressure boundary will have an extremely low probability of abnormal leakage, rapidly propagating failure, or gross rupture. Such a program provides for (1) determination of the principal location of leakage, (2) examinations and procedures for locating small leaks, and (3) engineering evaluations and corrective actions to provide reasonable assurance that boric acid corrosion does not lead to degradation of the leakage source or adjacent structures or components. Although NRC GL 88-05 addresses boric acid corrosion of reactor coolant pressure boundary components, the recommendations in NRC GL 88-05 are also effective in managing the aging of other in-scope components.

2 ***Preventive Actions:*** Minimizing borated water leakage by conducting frequent monitoring of the locations where potential leakage could occur and timely cleaning and repair if

leakage is detected prevents or mitigates boric acid corrosion. In addition, the use of corrosion-resistant materials and coatings minimizes the effects of boric acid exposure.

3 ***Parameters Monitored or Inspected:*** The AMP monitors the aging effects of loss of material due to boric acid corrosion on the intended function of an affected SC by detection of borated water leakage. Borated water leakage results in deposits of white boric acid crystals and the presence of moisture. Discolored boric acid crystals are an indication of corrosion. Boric acid deposits, borated water leakage, or the presence of moisture that could lead to the identification of loss of material can be monitored through visual examination.

To identify potential borated water leaks inside containment that have not been detected during walkdowns and maintenance, the program tracks airborne radioactivity monitors, humidity monitors, temperature monitors, reactor coolant system water inventory balancing, and containment air cooler thermal performance. The program also looks for evidence of boric acid deposits on control rod drive mechanism shroud fans, containment air recirculation fan coils, containment fan cooler units, and airborne filters.

4 ***Detection of Aging Effects:*** Degradation of the component due to boric acid corrosion cannot occur without leakage of borated water. Conditions leading to boric acid corrosion, such as crystal buildup and evidence of moisture, are readily detectable by visual inspection, though removal of insulation may be required in some cases. Obstructions to visual inspections are removed unless a technical justification is documented by the program owner. Criteria for removing insulation for bare-metal inspections include the safety significance of the location, evidence of leakage from under the insulation, bulging of the insulation, and operating experience (OE). Discoloration, staining, boric acid residue, and other evidence of leakage on insulation surfaces and the surrounding area are given particular consideration as evidence of component leakage. The program delineated in NRC GL 88-05 includes guidelines for locating small leaks, conducting examinations, and performing engineering evaluations. In addition, the program includes appropriate interfaces with other site programs and activities, such that borated water leakage that is encountered by means other than the monitoring and trending established by this program is evaluated and corrected.

5 ***Monitoring and Trending:*** This program provides monitoring and trending activities as delineated in NRC GL 88-05, timely evaluation of evidence of borated water leakage identified by other means, and timely detection of leakage by observing boric acid crystals during normal plant walkdowns and maintenance. The program maintains a list of all active borated water leaks, excessive boric acid deposits, discoloration caused by corrosion, and affected targets susceptible to corrosion to track the condition of components in the vicinity of leaks and to identify locations with repeat leakage.

6 ***Acceptance Criteria:*** All indications of boric acid leakage are screened to determine whether more detailed evaluations of the leaking component or associated targets are warranted. Any detected borated water leakage not meeting screening criteria (i.e., essentially zero potential for adverse effects on SCs), including white or discolored boric acid crystal buildup, or rust-colored deposits, is evaluated to confirm the intended functions of affected SCs consistent with the design basis prior to continued service.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal* Regulations (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50 (TN249), Appendix B, QA

program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

Borated water leakage and areas of resulting boric acid corrosion are evaluated and corrected in accordance with the applicable provisions of NRC GL 88-05 and the corrective action program. Any detected boric acid crystal buildup or deposits should be cleaned. NRC GL 88-05 recommends that corrective actions to prevent recurrences of degradation caused by borated water leakage be included in the program implementation. These corrective actions include any modifications to be introduced in the present design or operating procedures of the plant that (1) reduce the probability of reactor coolant leaks at locations where they may cause corrosion damage and (2) entail the use of suitable corrosion-resistant materials or the application of protective coatings or claddings. When corrective actions include the use of enclosures to contain borated water leakage, the impact of the leakage environment on the potential degradation mechanisms of enclosed components is evaluated (NRC Information Notice (IN) 2012-15). Such modifications should allow for periodic inspections.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Boric acid corrosion has been observed in nuclear power plants (NRC IN 86-108 [and Supplements 1 through 3], IN 2002-11, IN 2002-13, and IN 2003-02) and has resulted in significant impairment of component-intended functions in areas that are difficult to access/observe (NRC Bulletin 2002-01). Boric acid leakage can become airborne and can cause corrosion in locations other than in the vicinity of the leak (Licensee Event Reports [LER] 250/2010-005, LER 346/2002-008). Corrosion rates may be inaccurately predicted due to the installation of a different type of material than indicated on the design documents (LER 346/1998-009) or galvanic corrosion caused by wet boric acid crystals bridging between dissimilar metals (EPRI] 1000975]).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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XI.M11

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)

Program Description

This program addresses operating experience (OE) of degradation due to the primary water stress corrosion cracking (PWSCC) of components or welds constructed from certain nickel alloys (e.g., Alloy 600/82/182) and exposed to pressurized water reactor (PWR) primary coolant at elevated temperatures. The initiation and growth of PWSCC cracks have been shown to be a function of several variables, including but not limited to (1) temperature, (2) stress, (3) microstructure, (4) time, and (5) water chemistry. As a result, this program is informed by Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M2, “Water Chemistry.”

In addition to inspections designed to identify the cracking of nickel alloy components, this program includes inspections designed to potentially identify the presence of boric acid residues, which have been demonstrated by OE to lead to loss of material in susceptible carbon and low alloy steel components. Thus, this program is used in conjunction with GALL-SLR Report AMP XI.M10, “Boric Acid Corrosion.” Except as required in Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a, it is not the general intent of this program to manage the aging of components and welds constructed from PWSCC-resistant nickel alloys (e.g., Alloy 690/52/152).

Plants have implemented and maintained existing programs to manage cracking due to PWSCC for nickel alloy components and welds, consistent with Electric Power Research Institute (EPRI) Materials Reliability Program (MRP)-126. The scope of subsequent license renewal may identify additional nickel alloy components or welds to be included in the applicant’s aging management program.

Evaluation and Technical Basis

1 ***Scope of Program:*** The scope of this program includes three basic groups of components and materials: (1) all nickel alloy components and welds that are identified at the plant in accordance with the guidelines of EPRI MRP-126; (2) nickel alloy components and welds identified in American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code)[1] Cases N-770, N-729 and N-722, as incorporated by reference in 10 CFR 50.55a (TN249); and (3) components that are susceptible to corrosion by boric acid and may be affected by leakage of boric acid from nearby or adjacent nickel alloy components previously described. This program manages cracking due to PWSCC and loss of material due to boric acid corrosion.

2 ***Preventive Actions:*** This program is primarily a condition monitoring program. Because the cracking of nickel alloys is affected by water quality, this program is used in conjunction with GALL-SLR Report AMP XI.M2, “Water Chemistry.” Additionally, in accordance with 10 CFR 50.55a, an applicant may choose to mitigate component degradation in lieu of performing required inspections.

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

3 ***Parameters Monitored or Inspected:*** Components and welds within the scope of this program are inspected for evidence of PWSCC by volumetric, surface, or visual testing. If boric acid residues or corrosion products are discovered during these inspections, the potential for, or extent of, loss of material is evaluated by visual and quantitative methods.

4 ***Detection of Aging Effects:*** For nickel alloy components and welds addressed by regulatory requirements contained in 10 CFR 50.55a, inspections are conducted in accordance with 10 CFR 50.55a. Other nickel alloy components and welds within the scope of this program are inspected in accordance with the guidance in the EPRI MRP-126 report.

The program also performs a baseline volumetric or inner-diameter surface inspection of all susceptible nickel alloy branch line connections and associated welds as identified in Table 4-1 of EPRI MRP-126 if such components or welds are of a sufficient size to create a loss of coolant accident through a complete failure (guillotine break) or ejection of the component and the normal operating temperature of the components is 274 °C (Celsius; 525 °F [Fahrenheit]) or greater. The baseline inspection is performed prior to the subsequent period of extended operation using a qualified method in accordance with Appendix IV or VIII of ASME Code Section XI as incorporated by reference in 10 CFR 50.55a, or equivalent. Existing periodic inspections using volumetric or surface examination methods may be credited for the baseline inspection. If the baseline inspection indicates the occurrence of PWSCC, periodic volumetric or inner-diameter surface inspections are performed with adequate periodicity.

5 ***Monitoring and Trending:*** Reactor coolant leakage is calculated and trended on a routine basis in accordance with technical specifications to detect changes in the leakage rates (Regulatory Guide [RG] 1.45). Flaw evaluation through 10 CFR 50.55a is a means of monitoring cracking. Detected flaws are monitored and trended by performing periodic and successive inspections in accordance with ASME Code Cases N-770, N-729, and N-722, as incorporated by reference in 10 CFR 50.55a, and the guidelines in EPRI MRP-126.

6 ***Acceptance Criteria:*** Acceptance criteria are in accordance with applicable sections of Section XI of the ASME Code, as incorporated by reference in 10 CFR 50.55a. If any boric acid residue or corrosion product is detected, additional actions are performed to determine the source of leakage and the impact of boric acid corrosion on adjacent components.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Components with relevant unacceptable flaw indications are corrected for further services through an implementation of appropriate repair or replacement as dictated by 10 CFR 50.55a and industry guidelines (e.g., EPRI MRP-126). In addition, detection of leakage or evidence of cracking in susceptible components within the scope of this program require a scope expansion of current inspection and increased inspection frequencies for some components, as required by 10 CFR 50.55a and industry guidelines (e.g., EPRI MRP-126).

Repair and replacement procedures and activities must either comply with ASME Code Section XI, as incorporated in 10 CFR 50.55a or conform to applicable ASME Code Cases that have been endorsed in 10 CFR 50.55a by referencing the latest version of RG 1.147.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** This program addresses review of related OE, including plant-specific information, generic industry findings, and international data. Within the current regulatory requirements, as necessary, the applicant maintains a record of OE through the required update of the facility's inservice inspection program in accordance with 10 CFR 50.55a. Additionally, the applicant follows mandated industry guidelines developed to address OE in accordance with Nuclear Energy Institute (NEI)-03-08, "Guideline for the Management of Materials Issues."

PWSCC of Alloy 600 components has been observed in domestic and foreign PWRs (NRC Information Notice [IN] 90-10). The ingress of demineralizer resins also has occurred in operating plants (NRC IN 96-11). The Water Chemistry program, GALL-SLR Report AMP XI.M2, manages the effects of such excursions through monitoring and control of primary water chemistry. NRC Generic Letter 97-01 is effective in managing the effect of PWSCC. PWSCC has occurred in the vessel head penetration nozzles of U.S. PWRs as described in NRC Bulletins 2001-01, 2002-01, and 2002-02. In addition, PWSCC was observed in reactor vessel bottom-mounted instrument nozzles (NRC IN 2003-11, Supplement 1, and Licensee Event Report 530/2013-001-00).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE including research and development such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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XI.M12 THERMAL AGING EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL

Program Description

The reactor coolant system components are inspected in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI.[1] This inspection is augmented to detect the effects of loss of fracture toughness due to thermal aging embrittlement of cast austenitic stainless steel (CASS) piping components except for valve bodies. This aging management program (AMP) includes determination of the potential significance of thermal aging embrittlement of CASS components based on casting method, molybdenum content, nickel content, and percent ferrite. For components for which thermal aging embrittlement is “potentially significant” as defined below, aging management is accomplished through either (1) qualified visual inspections, such as enhanced visual examination (EVT-1); (2) a qualified ultrasonic testing (UT) methodology; or (3) a component-specific flaw tolerance evaluation in accordance with the ASME Code, Section XI. Additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required for components for which thermal aging embrittlement is not significant. The scope of the program includes ASME Code Class 1 piping components constructed from CASS with service conditions above 250 °C (Celsius; 482 °F [Fahrenheit]).

For pump casings, as an alternative to the screening and other actions described above, no further actions are needed if applicants demonstrate that the original flaw tolerance evaluation performed as part of Code Case N-481 implementation remains bounding and applicable for the subsequent license renewal (SLR) period or the evaluation is revised to be applicable for 80 years. For valve bodies, based on the results of the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, U.S. Nuclear Regulatory Commission (NRC), to Douglas Walters, Nuclear Energy Institute (May 19, 2000 NRC letter), screening for significance of thermal aging embrittlement is not required. The existing ASME Code, Section XI inspection requirements are adequate for valve bodies.

Reactor vessel internal (RVI) components fabricated from CASS are not within the scope of this AMP. Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M9, “BWR Vessel Internals” contains aging management guidance for CASS RVI components of boiling water reactors (BWRs). GALL-SLR Report AMP XI.M16A, “PWR Vessel Internals” contains aging management guidance for CASS RVI components of pressurized water reactors (PWRs).

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages loss of fracture toughness in ASME Code Class 1 piping components made from CASS. The program includes screening criteria to determine which CASS components have the potential for significant loss of fracture toughness due to thermal aging embrittlement and require augmented inspection. The screening criteria are applicable to all primary pressure boundary components constructed from CASS with service conditions above 250 °C (482 °F). The screening criteria for the significance of thermal aging embrittlement are not applicable to niobium-containing steels; such steels require evaluation on a case-by-case basis.

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[1] GALL-SLR Report. Chapter 1, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

Based on the criteria set forth in NUREG/CR–4513, Revision 2 with errata (March 2021), the potential significance of thermal aging embrittlement of CASS materials is determined in terms of casting method, molybdenum content, nickel content, and ferrite content. For low-molybdenum content steels (SA-351 Grades CF3, CF3A, CF8, CF8A or other steels with ≤0.5 weight percent [wt.%] Mo), only static-cast steels with >20 percent ferrite are potentially susceptible to thermal aging embrittlement (i.e., screens in). Static-cast low-molybdenum steels with ≤20 percent ferrite and all centrifugal cast low-molybdenum steels are not susceptible (i.e., screens out).

For high-molybdenum content steels with <10 wt.% nickel, static-cast steels with >14 percent ferrite and centrifugal-cast steels with >19 percent ferrite are potentially susceptible to thermal aging embrittlement (i.e., screens in). For high-molybdenum content steels with ≥10 wt.% nickel, static-cast steels with >11 percent ferrite and centrifugal-cast steels with >13 percent ferrite are potentially susceptible to thermal aging embrittlement (i.e., screens in). The screening criteria for CASS are described in Table XI.M12-1, “Thermal Embrittlement Screening Criteria.”

In the significance screening method, ferrite content is calculated by using the Hull’s equivalent factors (described in NUREG/CR–4513, Revision 2 with errata) or a staff-approved method for calculating delta ferrite in CASS materials. A fracture toughness value of 255 kilo-joules per square meter (kJ/m^2; 1,450 inch-pounds per square inch) at a crack extension of 2.5 millimeters (0.1 inch) is used to differentiate between CASS materials for which thermal aging embrittlement is not significant and those for which thermal aging embrittlement is potentially significant. Extensive research data indicate that for CASS materials without the potential for significant thermal aging embrittlement, the saturated lower-bound fracture toughness is greater than 255 kJ/m^2 (NUREG/CR–4513, Revision 2 with errata).

Table XI.M12-1. Thermal Embrittlement Screening Criteria

Molybdenum (Mo) Content	Ferrite Content	Casting Method	Potentially Significant (Screens In)	Not Significant (Screens Out)
Low or ≤ 0.5 wt.% maximum	>20% ferrite	Static	X	—
Low or ≤ 0.5 wt.% maximum	≤20% ferrite	Static	—	X
Low or ≤ 0.5 wt.% maximum	Any	Centrifugal	—	X
High or 2.0-3.0 wt.% with <10 wt.% Ni (≥10 wt.% Ni)	>14% Ferrite (>11% ferrite)	Static	X	—
High or 2.0-3.0 wt.% with <10 wt.% Ni (≥10 wt.% Ni)	>19% Ferrite (>13% ferrite)	Centrifugal	X	—
High or 2.0-3.0 wt.% with <10 wt.% Ni (≥10 wt.% Ni)	≤14% ferrite (≤11% ferrite)	Static	—	X
High or 2.0-3.0 wt.% with <10 wt.% Ni (≥10 wt.% Ni)	≤19% ferrite (≤13% ferrite)	Centrifugal	—	X

Ni = nickel; wt.% = weight percent.

For valve bodies, screening for significance of thermal aging embrittlement is not needed (and thus there are no aging management review items). For valve bodies greater than 4 inches nominal pipe size (NPS), the existing ASME Code, Section XI inspection requirements are adequate. ASME Code, Section XI, Subsection IWB requires only surface examination of valve bodies less than 4 inches NPS. For valve bodies less than 4 inches NPS, the adequacy of inservice inspection (ISI) according to ASME Code, Section XI has been demonstrated by an NRC-performed bounding integrity analysis (May 19, 2000 letter). For pump casings, as an alternative to screening for significance of thermal aging, no further actions are needed if applicants demonstrate that the original flaw tolerance evaluation performed as part of Code Case N-481 implementation remains bounding and applicable for the SLR period, or the evaluation is revised to be applicable to 80 years.

2 ***Preventive Actions:*** This program is a condition monitoring program and does not mitigate thermal aging embrittlement.

3 ***Parameters Monitored or Inspected:*** This program monitors the effects of loss of fracture toughness on the intended function of the component by identifying the CASS materials that are susceptible to thermal aging embrittlement.

The program does not directly monitor for loss of fracture toughness that is induced by thermal aging; instead, the impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components.

4 ***Detection of Aging Effects:*** For valve bodies, and other “not susceptible” CASS piping components, no additional inspection or evaluations are needed to demonstrate that the material has adequate fracture toughness.

For piping components for which thermal aging embrittlement is “potentially significant,” the AMP provides for qualified inspections of the base metal, such as EVT-1 or a qualified UT methodology, with the scope of the inspection covering the portions determined to be limiting from the standpoint of applied stress, operating time, and environmental considerations. Examination methods that meet the criteria of the ASME Code, Section XI, Appendix VIII are acceptable. Alternatively, a plant-specific or component-specific flaw tolerance evaluation, using specific geometry, stress information, material properties, and ASME Code, Section XI can be used to demonstrate that the thermally embrittled material has adequate toughness. For CASS piping, UT may be performed in accordance with the methodology of Code Case N-824, as conditioned by Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a.

5 ***Monitoring and Trending:*** Inspection schedules in accordance with ASME Code, Section XI, IWB-2400 or IWC-2400, reliable examination methods, and qualified inspection personnel provide timely and reliable detection of cracks. If flaws are detected, the period of acceptability is determined from analysis of the flaw, depending on the crack growth rate and mechanism.

6 ***Acceptance Criteria:*** Flaws detected in CASS components are evaluated in accordance with the applicable procedures of ASME Code, Section XI. Nonmandatory Appendix C to the 2019 Edition of ASME Code, Section XI, has been incorporated by reference in 10 CFR 50.55a. Nonmandatory Appendix C to the 2019 ASME Code, Section XI, provides flaw evaluation procedures for CASS with ferrite content ≥20 percent. The procedures may be used for flaw evaluations or flaw tolerance evaluations in this program, as incorporated by reference in 10 CFR 50.55a. This program may also use the flaw evaluation or flaw tolerance evaluation methods in the NRC-approved code cases that are documented in the latest revision of Regulatory Guide 1.147. NUREG/CR–4513, Revision 12 with errata provides methods for predicting the fracture toughness of thermally aged CASS materials with delta ferrite content up to 40 percent.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Repair and replacement are performed in accordance with ASME Code, Section XI, IWA-4000.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** This AMP was developed by using research data obtained about both laboratory-aged and service-aged materials. Based on this information, the effects of thermal aging embrittlement on the intended function of CASS components will be effectively managed.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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ASME. ASME Code Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." New York, New York: The American Society of Mechanical Engineers. 2008.[2]

[2] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

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NRC. NUREG/CR–4513, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems.” Revision 2 with errata. Washington, DC: U.S. Nuclear Regulatory Commission. March 2021.

_____. Regulatory Guide 1.147, Revision 20, “Inservice Inspection Code Case Acceptability.” Washington, DC: U.S. Nuclear Regulatory Commission. December 2021.

XI.M16 PWR VESSEL INTERNALS

XI.M16A PWR VESSEL INTERNALS

Program Description

This program is used to manage the effects of age-related degradation mechanisms that are applicable to the pressurized water reactor (PWR) reactor vessel internal (RVI) components. These aging effects include (1) cracking, including stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation-assisted stress corrosion cracking (IASCC), and cracking due to fatigue/cyclic loading; (2) loss of material due to wear; (3) loss of fracture toughness due to thermal aging and neutron irradiation embrittlement; (4) changes in dimensions due to void swelling or distortion; and (5) loss of preload due to thermal and irradiation-enhanced stress relaxation or creep.

In the absence of an acceptable generic report such as an approved revision of Materials Reliability Program (MRP)-227 that considers an operating period of 80 years, this program may be based on an existing plant program that is consistent with Electric Power Research Institute (EPRI) Topical Report No. 3002017168, “Materials Reliability Program: Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A),” which is implemented in accordance with Nuclear Energy Institute (NEI) 03-08, “Guideline for the Management of Materials Issues.” The staff found the updated I&E guidelines and criteria for PWR RVI components to be acceptable, as documented in the staff’s safety evaluation of April 25, 2019 (ADAMS Accession No. ML19081A001), and approved the use of MRP-227, Revision 1-A, for PWR-specific design bases in the staff’s letters to the EPRI MRP dated February 19, 2020 and July 7, 2020 (ADAMS Accession Nos. ML20006D152 and ML20175A149).

Because the guidelines of MRP-227, Revision 1-A are based on an analysis of the RVIs that considers the operating conditions up to a 60-year operating period, these guidelines are supplemented through a gap analysis that identifies enhancements to the program that are needed to address an 80-year operating period. In this program, the term “MRP-227 (as supplemented)” is used to describe either MRP-227, Revision 1-A as supplemented by this gap analysis, or an acceptable generic report such as an approved revision of MRP-227 that considers an operating period of 80 years.

This program applies the guidance in MRP-227 (as supplemented) for inspecting, evaluating, and, if applicable, dispositioning nonconforming RVI components at the facility. These examinations provide reasonable assurance that the effects of the mechanisms of age-related degradation will be managed during the period of extended operation. The program includes expanding periodic examinations and other inspections, if the extent of the degradation identified exceeds the expected levels.

The methodology described in MRP-227, Revision 1-A for selecting RVI components for inclusion in the inspection sample is based on a four-step ranking process. Through this process, the RVIs for Westinghouse and Combustion Engineering (CE) PWR designs were assigned to one of the following four inspection categories: “Primary,” “Expansion,” “Existing Programs,” or “No Additional Measures.” Through this process, the RVIs for Babcock & Wilcox (B&W) PWR designs were assigned to one of the following three inspection categories: “Primary,” “Expansion,” or “No Additional Measures.” Definitions of each category are provided in MRP-227, Revision 1-A.

The result of the four-step sample selection process is a set of “Primary” internal component locations for each of the three plant designs that are inspected, because they are expected to show the leading indications of the degradation effects. The category of “Expansion” internal component locations is specified to expand the sample in case the indications from the “Primary” components are more severe than anticipated.

The degradation effects in a third set of internal locations (which apply only to the RVI components in Westinghouse- or CE-designed PWRs) are deemed to be adequately managed by “Existing Programs,” such as American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI,[1] Examination Category B-N-3, examinations of core support structures. A fourth set of internal locations is deemed to require “No Additional Measures.”

In the absence of an acceptable generic report such as an approved revision of MRP-227 that considers an operating period of 80 years, the gap analysis described below is used to provide reasonable assurance that the aging management activities designated for the RVI components identified in the four groups is appropriate for 80 years of operation. The gap analysis may include and incorporate supplemental guidelines developed and recommended for the RVI components.

If the program is based on MRP-227, Revision 1-A with a gap analysis, the inspection categories, inspection criteria, and other program characteristics established in MRP-227, Revision 1-A, are identified and justified for each component in the applicable program elements. The justification should focus on the aging management of any additional aging considerations (i.e., new aging effect/mechanism) during the subsequent period of extended operation. The acceptance criteria in the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR), Section 3.1.2.2.9 and the review procedures in Section 3.1.3.2.9 provide additional information.

Evaluation and Technical Basis

1. ***Scope of Program:*** The scope of the program includes all RVI components based on the plant’s applicable nuclear steam supply system design. The scope of the program applies the guidelines in MRP-227 (as supplemented), which provides an augmented inspection and flaw evaluation guidelines for assuring the functional integrity of safety-related internal components in commercial operating U.S. PWR nuclear power plants designed by B&W, CE, and Westinghouse. Because these types of AMPs are considered to be “living” programs by the licensees implementing the programs, the scope of the program may also include additional reports, documents, or guidelines recommended for implementation by the EPRI MRP, PWR Owners Group, or industry vendors. This may include (but is not limited to) applicable WCAP or BAW technical/topical reports issued by Westinghouse or B&W, or supplemental guidelines or industry alert letters issued by the EPRI MRP, PWR Owners Group, or industry vendors. The scope of components includes core support structures, the RVI components that serve an intended license renewal safety function pursuant to criteria in Title 10 of the *Code of Federal Regulations* (10 CFR) 54.4(a)(1), and other RVI components whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4 (TN4878)(a)(1)(i), (ii), or (iii). In addition, ASME Code, Section XI includes inspection requirements for PWR removable core support

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

structures in Table IWB-2500-1, Examination Category B-N-3, which are in addition to any inspections that are implemented in accordance with MRP-227 (as supplemented).

The scope of the program does not include consumable items, such as fuel assemblies, reactivity control assemblies, and nuclear instrumentation. The scope of the program also does not include attachments welded to the internal surface of the reactor vessel because these components are considered to be ASME Code Class 1 appurtenances to the reactor vessel and are managed in accordance with an applicant's AMP that corresponds to Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M1, "ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."

This program element specifies whether the program is based on an existing program that is consistent with MRP-227, Revision 1-A, with a gap analysis, or whether the program is based on an acceptable generic report that covers an 80-year service life for the RVI components, such as an approved revision of MRP-227 that considers an operating period of 80 years. If it is based on MRP-227, Revision 1-A with a gap analysis, the scope of the program focuses on identification and justification of the following:

- Components that screen in for additional aging effects or mechanisms when assessed for the 60–80 year operating period.
- Components that previously screened in for an aging effect or mechanism and the severity of that aging effect or mechanism could significantly increase for the 60- to 80-year operating period.
- Changes in the existing MRP-227, Revision 1-A program characteristics or criteria, including but not limited to changes in inspection categories, inspection criteria, or primary-to-expansion component criteria and relationships.

2 ***Preventive Actions:*** The program relies on PWR water chemistry control to prevent or mitigate aging effects that can be induced by corrosive aging mechanisms (e.g., loss of material induced by general, pitting corrosion, crevice corrosion, or stress corrosion cracking or any of its forms [SCC, PWSCC, or IASCC]). Reactor coolant water chemistry is monitored and maintained in accordance with the Water Chemistry program, as described in GALL-SLR Report AMP XI.M2, "Water Chemistry."

3 ***Parameters Monitored or Inspected:*** The program manages the following age-related degradation effects and mechanisms that are applicable in general to RVI components at the facility: (1) cracking due to SCC, PWSCC, IASCC, or fatigue/cyclic loading; (2) loss of material due to wear; (3) loss of fracture toughness due to thermal aging and neutron irradiation embrittlement; (4) changes in dimensions due to void swelling or distortion; and (5) loss of preload due to thermal and irradiation-enhanced stress relaxation or creep.

For the management of cracking, the program monitors for evidence of surface-breaking linear discontinuities if a visual inspection technique is used as the nondestructive examination (NDE) method or for relevant flaw presentation signals if a volumetric ultrasonic testing (UT) method is used as the NDE method. For the management of loss of material, the program monitors for gross or abnormal surface conditions that may be indicative of loss of material occurring in the components. For the management of loss of preload, the program monitors for gross surface conditions that may be indicative of loosening in applicable bolted, fastened, keyed, or pinned connections. The program does not directly monitor for loss of fracture toughness that is induced by thermal aging or neutron irradiation embrittlement. Instead, the impact of loss of fracture toughness on component integrity is indirectly managed by (1) using visual or volumetric examination techniques to monitor for cracking in the components, and (2) applying applicable reduced fracture toughness properties in the flaw evaluations, in cases where cracking is detected in the components and is extensive enough to necessitate a supplemental flaw growth or flaw tolerance evaluation. The program uses physical measurements to monitor for any dimensional changes due to void swelling or distortion.

Specifically, the program implements the parameters monitored/inspected criteria consistent with the applicable tables in Section 4, “Aging Management Requirements,” in MRP-227-A (as supplemented).

4 ***Detection of Aging Effects:*** The inspection methods are defined and established in Section 4 of MRP-227, Revision 1-A, or MRP-227 (as supplemented). Standards for implementing the inspection methods are defined and established in MRP-228. In all cases, well-established inspection methods are selected. These methods include volumetric UT examination methods for detecting flaws in bolting and various visual (VT-3, VT-1, and EVT-1) examinations for detecting effects ranging from general conditions to detection and sizing of surface-breaking discontinuities. Surface examinations may also be used as an alternative to visual examinations for the detection and sizing of surface-breaking discontinuities.

Cracking caused by SCC, IASCC, and fatigue is monitored/inspected by either VT-1 or EVT-1 examination (for internals other than bolting) or by volumetric UT examination (bolting). VT-3 visual methods may be applied for the detection of cracking in nonredundant RVI components only when the flaw tolerance of the component, as evaluated for reduced fracture toughness properties, is known and the component has been shown to be tolerant of easily detected large flaws, even under reduced fracture toughness conditions. VT-3 visual methods are acceptable for the detection of cracking in redundant RVI components (e.g., redundant bolts or pins used to secure a fastened RVI assembly).

In addition, VT-3 examinations are used to monitor/inspect for loss of material induced by wear and for general aging conditions, such as gross distortion caused by void swelling and irradiation growth or by gross effects of loss of preload caused by thermal and irradiation-enhanced stress relaxation and creep.

The program adopts the guidance in MRP-227 (as supplemented) for defining the “Expansion Criteria” that need to be applied to the inspection findings of “Primary” components and for expanding the examinations to include additional “Expansion” components. RVI component inspections are performed consistent with the inspection frequency and sampling bases for “Primary” components, “Existing Programs” components, and “Expansion” components in MRP-227 (as supplemented).

In some cases (as defined in MRP-227, Revision 1-A), physical measurements are used as supplemental techniques to manage for the gross effects of wear, loss of preload due to stress relaxation, or for changes in dimensions due to void swelling or distortion.

Inspection coverages for “Primary” and “Expansion” RVI components are implemented consistent with those established in MRP-227 (as supplemented).

This program element should justify the appropriateness of the inspection methods, sample size criteria, and inspection frequency criteria for managing the effects of degradation during the subsequent period of extended operation, including any changes in these criteria from their assessment in MRP-227, Revision 1-A.

5 ***Monitoring and Trending:*** The methods for monitoring, recording, evaluating, and trending the data that result from the program’s inspections are given in Section 6 of MRP-227, Revision 1-A and its subsections, or MRP-227 (as supplemented). Component reinspection frequencies for “Primary” and “Expansion” category components are defined in specific tables in Section 4 of the MRP-227, Revision 1-A report or in MRP-227 (as supplemented). The examination and reexaminations that are implemented in accordance with MRP-227 (as supplemented), together with the criteria specified in MRP-228, Revision 3 for inspection standards, inspection procedures, and inspection personnel, provide for timely detection, reporting, and implementation of corrective actions for the aging effects and mechanisms managed by the program.

The program applies applicable fracture toughness properties, including reductions for thermal aging or neutron embrittlement, in the flaw evaluations of the components in cases where cracking is detected in an RVI component and is extensive enough to warrant a supplemental flaw growth or flaw tolerance evaluation.

For singly represented components, the program includes criteria to evaluate the aging effects in the inaccessible portions of the components and the resulting impact on the intended function(s) of the components. For redundant components (such as redundant bolts, screws, pins, keys, or fasteners, some of which are accessible to inspection and some of which are not accessible to inspection), the program includes criteria for evaluating the aging effects in the populations of components that are inaccessible by the applicable inspection technique and the resulting impact on the intended function(s) of the assembly containing the components.

Flaw evaluation methods, including recommendations for flaw depth sizing and for crack growth determinations, as well as for performing applicable limit load, linear elastic, and elastic-plastic fracture analyses of relevant flaw indications, are defined in MRP-227 (as supplemented).

6 ***Acceptance Criteria:*** Section 5 of MRP-227, Revision 1-A, which includes Table 5-1 for B&W-designed RVIs, Table 5-2 for CE-designed RVIs, and Table 5-3 for Westinghouse-designed RVIs, or MRP-227 (as supplemented) provides the specific examination and flaw evaluation acceptance criteria for the “Primary” and “Expansion” RVI component examination methods. Consistent with the criteria in MRP-227, Revision 1-A, the acceptance criteria for some “Expansion” category components may be established through performance of a component-specific analysis or component replacements, particularly if the components are inaccessible for inspection or the industry has yet to develop adequate inspection methods for the components. For RVI components addressed by examinations performed in accordance with the ASME Code, Section XI, the acceptance criteria in IWB-3500 are applicable. For RVI components covered by other “Existing Programs,” the acceptance criteria are described in the applicable reference document. As applicable, the program establishes acceptance criteria for any physical measurement monitoring methods that are credited for aging management of particular RVI components.

This program element should justify the appropriateness of the acceptance criteria for managing the effects of degradation during the subsequent period of extended operation, including any changes in acceptance criteria based on the gap analysis.

7 ***Corrective Actions*****:** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Any detected conditions that do not satisfy the examination acceptance criteria are required to be dispositioned through the plant corrective action program, which may require repair, replacement, or analytical evaluation for continued service until the next inspection. The disposition will ensure that design basis functions of the reactor internal components will continue to be fulfilled for all licensing basis loads and events. The implementation of the guidance in MRP-227 (as supplemented), plus the implementation of any ASME Code requirements, provides an acceptable level of aging management of safety-related components addressed in accordance with the corrective actions of 10 CFR Part 50, Appendix B or its equivalent, as applicable.

Other alternative corrective action bases may be used to disposition relevant conditions if they have been previously approved or endorsed by the NRC. Alternative corrective actions not approved or endorsed by the NRC will be submitted for NRC approval prior to their implementation.

8 ***Confirmation Process*****:** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the recommendations of NEI 03-08 and the requirements of 10 CFR Part 50, Appendix B, or their equivalent, as applicable. The implementation of the guidance in Section 7 of MRP-227, Revision 1-A, in conjunction with NEI 03-08 and other guidance documents, reports, or guidelines referenced in this AMP, provides an acceptable level of quality and an acceptable basis for confirming the quality of inspections, flaw evaluations, and corrective actions.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50 (TN249), Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

The administrative controls for these types of programs, including their implementing procedures and review and approval processes, are implemented in accordance with the recommended industry guidelines and criteria in NEI 03-08 and are under existing site 10 CFR 50 Appendix B, Quality Assurance Programs, or their equivalent, as applicable. The basis defined in Section 7 of MRP-227, Revision 1-A, found acceptable as documented in the staff's safety evaluation dated April 25, 2019, provides the basis for implementing the program in accordance with NEI 03-08. Administrative activities for keeping the program implementation procedures up to date with the various industry reports within the scope of the AMP (e.g., MRP-227, Revision 1-A) fall within the scope of this "Administrative Controls" program element.

10 ***Operating Experience:*** The review and assessment of relevant operating experience (OE) for its impacts on the program, including implementing procedures, are governed by NEI 03-08 and Appendix A of MRP-227, Revision 1-A. Consistent with MRP-227, Revision 1-A, the reporting of inspection results and OE is treated as a "Needed" category item under the implementation of NEI 03-08.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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[2]GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

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XI.M17 FLOW-ACCELERATED CORROSION

Program Description

This program manages wall thinning caused by flow-accelerated corrosion (FAC), and may also be used to manage wall thinning due to erosion mechanisms, if present, that are not being managed by another program. The program is based on commitments made for an ongoing monitoring program in response to the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-08, and relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L[1] report about implementing an effective FAC program. The program includes (1) identifying all susceptible piping systems and components; (2) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (3) performing analyses of FAC models and, with consideration of operating experience (OE), selecting a sample of components for inspection; (4) inspecting components; (5) evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (6) incorporating inspection data to refine FAC models. The program includes the use of predictive analytical software, such as CHECWORKS™, that uses the implementation guidance of NSAC-202L, which recommends inclusion of quality assurance (QA) requirements. Any currently performed software QA activities (e.g., validation and verification, error reporting) for each software program used in the FAC program should continue, even though these activities may not be required by the software QA classification.

This program may also manage wall thinning caused by mechanisms other than FAC in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms. Guidance in EPRI 3002005530, “Recommendations for an Effective Program Against Erosive Attack,” can be used to manage erosion mechanisms.

Evaluation and Technical Basis

1 ***Scope of Program:*** The FAC program, described by the EPRI guidelines in NSAC-202L, includes procedures or administrative controls to assure that structural integrity is maintained for carbon steel piping components containing single- and two-phase flow conditions. This program also includes the pressure-retaining portions of pump and valve bodies within these systems. The FAC program was originally outlined in NUREG–1344 and was further described in NRC GL 89-08. The program may also include components that are subject to wall thinning due to erosion mechanisms such as cavitation, flashing, droplet impingement, or solid particle impingement in various water systems. Because no materials are known to be totally resistant to wall thinning due to erosion mechanisms, susceptible components of any material may be included in the erosion portion of the program.

2 ***Preventive Actions:*** This is a condition monitoring program; no preventive action has been recommended in this program. However, it is noted that monitoring of water chemistry to control pH and dissolved oxygen content are effective in reducing FAC, and the selection of appropriate component material, geometry, and hydrodynamic conditions can be effective in reducing both FAC and erosion mechanisms.

[1] As described in this AMP-R2 (Revision 2), -R3 (Revision 3), and –R4 (Revision 4) of NSAC-202L are acceptable versions of the EPRI guideline.

3 ***Parameters Monitored or Inspected:*** This aging management program (AMP) monitors the effects of wall thinning due to FAC and erosion mechanisms by measuring wall thicknesses. In addition, relevant changes in system operating parameters (e.g., temperature, flow rate, water chemistry, operating time) that result from off-normal or reduced-power operations are considered for their effects on the FAC models. Also, opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation.

4 ***Detection of Aging Effects:*** Degradation of piping and components occurs by wall thinning. For FAC, the inspection program delineated in NSAC-202L includes identification of susceptible locations, as indicated by operating conditions or special considerations. For periods of extended operation beyond 60 years, piping systems that have been excluded from wall thickness monitoring due to operating for less than 2 percent of plant operating time (as allowed by NSAC-202L) will be reassessed to ensure adequate bases exist to justify this exclusion. If actual wall thickness information is not available for use in this assessment, a representative sampling approach can be used. This program specifies nondestructive examination methods, such as ultrasonic testing (UT) and/or radiographic testing, to quantify the extent of wall thinning. Opportunistic visual inspections of upstream and downstream piping and components are performed during periodic pump and valve maintenance or during pipe replacements to assess internal surface conditions. Wall thicknesses are also measured at locations of suspected wall thinning that are identified by internal visual inspections. A representative sample of components is selected based on the most susceptible locations for wall thickness measurements at a frequency in accordance with NSAC-202L guidelines to identify and mitigate degradation before the component integrity is challenged. Expansion of the inspection sample is described in NSAC-202L, following identification of unexpected or inconsistent inspection results in the initial sample, and includes (1) at least the next two most susceptible components in the relative wear ranking in the same train, (2) similar components in other trains of a multi-train system, and (3) components within two diameters of the affected component. NSAC-202L includes additional scope expansion guidance if the expanded inspections detect additional significant FAC wear. Scope expansion inspections should be independently reviewed by a qualified individual in a manner similar to recommendations in NSAC-202L for initial inspection locations. The extent and schedule of the inspections provide for the detection of wall thinning before the loss of intended function. Inspections are performed by personnel qualified in accordance with site procedures and programs to perform the specified task.

For erosion mechanisms, the program includes the identification of susceptible locations based on the extent-of-condition reviews from corrective actions in response to plant-specific and industry OE. Erosion susceptibility screening, as provided in EPRI 3002005530, can augment erosion location identification. However, system exclusion for cavitation screening should be based on less than 100 hours of operation per year (as provided in EPRI TR-112657) instead of the specified 2 percent exclusion criterion. Susceptibility screening should consider the severity of cavitation and OE should be used to validate susceptibility screening results, especially for valve throttling situations. Components in this category may be treated in a manner similar to other “susceptible-not-modeled” lines discussed in NSAC-202L. EPRI 1011231 provides guidance for identifying potential damage locations. EPRI TR-112657 or NUREG/CR-6031 provides additional insights for cavitation.

5 ***Monitoring and Trending:*** For FAC, CHECWORKS™ or similar predictive software calculates component wear rates and the remaining service life based on inspection data and changes in operating conditions (e.g., power uprate, water chemistry). Data from each component inspection are used to calibrate the wear rates calculated in the FAC model with the observed field data. The use of such predictive software to develop an inspection schedule provides reasonable assurance that structural integrity will be maintained between inspections. The program includes the evaluation of inspection results to determine whether additional inspections are needed to provide reasonable assurance that the extent of wall thinning is adequately determined, that its intended function will not be lost, and that corrective actions are adequately identified.

For erosion mechanisms, the program includes trending of wall thickness measurements to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements. Inspection results are evaluated to determine whether assumptions in the extent-of-condition review remain valid. If degradation is associated with infrequent operational alignments, such as surveillances or pump starts/stops, then trending activities may need to consider the number or duration of these occurrences. Periodic wall thickness measurements of replacement components may be required and should continue until the effectiveness of corrective actions has been confirmed.

6 ***Acceptance Criteria:*** Components are suitable for continued service if calculations determine that the predicted wall thickness when the next scheduled inspection occurs will meet the minimum allowable wall thickness. The minimum allowable wall thickness is the thickness needed to satisfy the component's design loads under the original code of construction, but additional code requirements may also need to be met. A conservative safety factor is applied to the predicted wear rate determination to account for uncertainties in the wear rate calculations and UT measurements. As discussed in NSAC-202L, the minimum safety factor for acceptable wall thickness and remaining service life in FAC evaluations should not be less than 1.1. As discussed in EPRI 3002005530, the minimum safety factor should not be less than 2.0 for determinations of erosion mechanism re-inspection intervals.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

The program includes reevaluation, repair, or replacement of components for which the acceptance criteria are not satisfied, prior to their return to service. For FAC, long-term corrective actions could include adjusting operating parameters or replacing components with FAC-resistant materials. However, if the wear mechanism has not been identified, then the replaced components should remain in the inspection program because FAC-resistant materials do not protect against erosion mechanisms. Furthermore, when carbon steel piping components are replaced with FAC-resistant material, the susceptible components immediately downstream should be monitored to identify any increased wear due to the "entrance effect," as discussed in EPRI 1015072.

For erosion mechanisms, long-term corrective actions to eliminate the cause could include adjusting operating parameters and/or changing components' geometric designs; however, the effectiveness of these corrective actions should be verified. Periodic monitoring activities should continue for any component replaced with an alternate material, because a material that is completely resistant to erosion mechanisms is not available.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Software QA activities (e.g., validation and verification, error reporting) that are currently being performed for each software program used in the FAC program should continue, even though these activities may not be required by the software QA classification. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems (NRC Bulletin 87-01; NRC Information Notice [IN] 92-35, IN 95-11, IN 2006-08) and in two-phase piping in extraction steam lines (NRC IN 89-53, IN 97-84) and moisture separator reheater and feedwater heater drains (NRC IN 89-53, IN 91-18, IN 93-21, IN 97-84). Observed wall thinning may be due to mechanisms other than FAC or, less commonly, due to a combination of mechanisms (NRC IN 99-19, Licensee Event Report [LER] 483/1999-003, LER 499/2005-004, LER 277/2006-003, LER 237/2007-003, LER 254/2009-004, LER 374/2013-001, LER 374/2015-001). Recent events associated with legacy FAC modeling issues are discussed in NRC IN 2019-08 and associated LERs.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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XI.M18 BOLTING INTEGRITY

Program Description

This program manages the aging of closure bolting for pressure-retaining components. The program relies on recommendations for a comprehensive bolting integrity program, as delineated in the following documents:

- NUREG–1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants"
- Electric Power Research Institute (EPRI) NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants" (with the exceptions noted in NUREG–1339 for safety-related bolting)
- EPRI Report 1015336, "Nuclear Maintenance Application Center: Bolted Joint Fundamentals"
- EPRI Report 1015337, "Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints."

The program includes periodic visual inspection of closure bolting for indications of loss of preload, cracking, and loss of material due to general, pitting, and crevice corrosion, microbiologically influenced corrosion (MIC), and wear as evidenced by leakage. Closure bolting that is submerged or located in piping systems that contain air or gas for which leakage is difficult to detect, is inspected or tested by alternative means. The program also includes sampling-based volumetric examinations of high-strength closure bolting to detect indications of cracking. It also includes preventive measures to preclude or minimize loss of preload and cracking.

Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M1, "ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD," manages aging effects associated with closure bolting within the scope of American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Section XI and supplements this bolting integrity program. GALL-SLR Report AMPs XI.S1, "ASME Section XI, Subsection IWE," XI.S3, "American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Section XI, Subsection IWF," XI.S6, "Structures Monitoring," XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," manage aging effects associated with safety-related and nonsafety-related structural bolting, and GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," manages aging effects associated with heating, ventilation, and air conditioning (HVAC) closure bolting.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages the effects of aging of closure bolting for pressure-retaining components (aging effects associated with HVAC closure bolting are managed by GALL-SLR Report AMP XI.M36) within the scope of license renewal. This program does not manage aging of reactor head closure stud bolting (GALL-SLR Report AMP XI.M3) or structural bolting (GALL-SLR Report AMPs XI.S1, XI.S3, XI.S6, XI.S7, and XI.M23).

2 ***Preventive Actions:*** Selection of bolting material and the use of lubricants and sealants are conducted in accordance with the guidelines in EPRI Reports 1015336 and 1015337 and the additional recommendations of NUREG–1339 to prevent or mitigate stress corrosion cracking (SCC). Of particular note, use of molybdenum disulfide (MoS_2) as a lubricant has been shown to be a potential contributor to SCC and should not be used. Preventive measures also include using bolting material that has an actual measured yield strength less than 150 kilo-pounds per square inch (ksi) or 1,034 megapascals (MPa). Bolting replacement activities include proper torquing of the bolts and checking for uniformity of the gasket compression after assembly. Maintenance practices require the application of an appropriate preload based on guidance in EPRI documents, manufacturer recommendations, or engineering evaluation.

3 ***Parameters Monitored or Inspected:*** This program monitors the effects of aging on the intended function of closure bolting. Closure bolting is inspected for signs of leakage. Closure bolting in locations that preclude detection of joint leakage, such as in submerged environments or where the piping systems contain air or gas for which leakage is difficult to detect,are inspected or tested by alternative means. High-strength closure bolting (with actual yield strengths greater than or equal to 150 ksi [1,034 MPa]), and bolting for which yield strength is unknown, is monitored for surface and subsurface discontinuities indicative of cracking.

4 ***Detection of Aging Effects:*** AMP XI.M1 implements inspection of Class 1, Class 2, and Class 3 pressure-retaining bolting in accordance with requirements of ASME Code Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. These include volumetric and visual (i.e., VT-1, VT-2) examinations, as appropriate.

Degradation of pressure boundary closure bolting due to crack initiation, loss of preload, or loss of material may result in leakage from the mating surfaces or joint connections of pressure boundary components. Periodic inspections of ASME Code class and non-ASME Code class bolted joints for signs of leakage are conducted at least once per refueling cycle. The inspections may be performed as part of ASME Code Section XI leakage tests or as part of other periodic inspection activities, such as system walkdowns or GALL-SLR Report AMP XI.M36 inspections. Bolted joints that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would provide reasonable assurance the components' intended functions are maintained. Closure bolting inspections include consideration of the guidance applicable for pressure boundary bolting in NUREG–1339 and in EPRI NP-5769.

High-strength closure bolting (actual measured yield strength greater than or equal to 150 ksi [1,034 MPa]) may be subject to SCC. For all closure bolting greater than 2 inches in diameter (regardless of code classification) with actual yield strengths greater than or equal to 150 ksi (1,034 MPa) and closure bolting for which yield strength is unknown, volumetric examination in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, is performed (e.g., acceptance standards, extent and frequency of examination). Specified bolting material properties (e.g., design and procurement specifications, fabrication and vendor drawings, material test reports) may be used to determine whether the bolting exceeds the threshold to be classified as high strength.

Closure bolting in locations that preclude detection of joint leakage, such as in submerged environments or where the piping systems contain air or gas for which leakage is difficult to detect, is inspected as follows:

- Submerged closure bolting is visually inspected for loss of material during maintenance activities. In this case, bolt heads are inspected when made accessible, and bolt threads are inspected when joints are disassembled. In each 10-year period during the subsequent period of extended operation a representative sample of bolt heads and threads is inspected. If opportunistic maintenance activities will not provide access to 20 percent of the population (for a material/environment combination) up to a maximum of 25 bolt heads and threads over a 10-year period, then the subsequent license renewal application (SLRA) states how the integrity of the bolted joint will be demonstrated. For example: (1) periodic pump vibration measurements are taken and trended; or (2) sump pump operator walkdowns are performed demonstrating that the pumps are appropriately maintaining sump levels.

- For closure bolting where the piping systems contain air or gas for which leakage is difficult to detect, the SLRA states how the integrity of the bolted joint will be demonstrated. For example: (1) inspections are performed consistent with those of submerged closure bolting; (2) a visual inspection for discoloration is conducted when leakage of the environment inside the piping systems would discolor the external surfaces; (3) monitoring and trending of pressure decay is performed when the bolted connection is located within an isolated boundary; (4) soap bubble testing is performed; or (5) when the temperature of the fluid is higher than ambient conditions, thermography testing is performed.

- For closure bolting for components that are not normally pressurized, the SLRA states how aging effects associated with the closure bolting will be managed (e.g., checking the torque to the extent that the closure bolting is not loose).

The inspection includes a representative sample of 20 percent of the population of bolt heads and threads (defined as bolts with the same material and environment combination) or a maximum of 25 bolts per population at each unit. For multi-unit sites where the sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections at the site as follows. For two-unit sites, 19 bolt heads and threads are inspected per unit and for a three-unit site, 17 bolt heads and threads are inspected per unit. To conduct 17 or 19 inspections at a unit in lieu of 25, the applicant states in the SLRA the basis for why the operating conditions at each unit are similar enough (e.g., chemistry) to provide representative inspection results. The basis should include consideration of potential differences such as the following:

- Are there any systems that have had an out-of-spec water chemistry condition for a longer period of time or out-of-spec conditions that occurred more frequently?

- For lubricating or fuel oil systems, are there any components that were exposed to the more severe contamination levels?

- For raw water systems, is the water derived from different sources where one or the other is more susceptible to microbiologically influenced corrosion or other aging mechanisms?

Inspections are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspections follow site procedures that include inspection parameters for items such as lighting, distance, and offset, which provide an adequate examination.

5 ***Monitoring and Trending:*** Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components’ intended functions throughout the subsequent period of extended operation based on the projected rate of

degradation. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

6 ***Acceptance Criteria:*** Any indications of aging effects in ASME pressure-retaining bolting are evaluated in accordance with Section XI of the ASME Code. Leaking joints do not meet the acceptance criteria. Plant-specific acceptance criteria are established when alternative inspections or testing is conducted for submerged closure bolting or closure bolting where the piping systems contains air or gas for which leakage is difficult to detect.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Replacement of ASME pressure-retaining bolting is performed in accordance with the requirements of ASME Code Section XI, subject to the additional guidelines and recommendations of EPRI Reports 1015336 and 1015337. Replacement of other pressure-retaining closure bolting (i.e., non-ASME Code class closure bolting) is performed in accordance with the guidelines and recommendations of EPRI Reports 1015336 and 1015337.

If a bolted connection for pressure-retaining components is reported to be leaking, follow-up periodic visual inspections are conducted in accordance with plant-specific procedures until the leak is corrected. If the leak rate is increasing, more frequent inspections are warranted. The effects of leakage from bolted connections that have an intended function identified in 10 CFR 54.4(a)(2)(TN4878) are evaluated for their impacts on components with an intended function identified in 10 CFR 54.4(a)(1) and located within the vicinity of the leaking bolted connection.

For sampling-based inspections, if the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement of all components constructed of the same material and exposed to the same environment, additional inspections are conducted if one of the inspections does not meet the acceptance criteria. The number of increased inspections is determined in accordance with the site's corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet the acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. If subsequent inspections do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections needed. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. At multi-unit sites, the additional inspections include inspections at all of the units that have the same material, environment, and aging effect combination. The additional inspections are completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted. If any projected inspection results will not meet the acceptance criteria prior to the next scheduled inspection, sampling frequencies are adjusted as determined by the site's corrective action program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50 (TN249), Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred as a result of boric acid corrosion, SCC, and fatigue loading (NRC Inspection and Enforcement Bulletin [IEB] 82-02, NRC Generic Letter [GL] 91-17). SCC has occurred in high-strength bolts used for nuclear steam supply system component supports (EPRI NP-5769). The bolting integrity program developed and implemented in accordance with the applicant’s docketed responses to the U.S. Nuclear Regulatory Commission (NRC) communications about bolting events have provided an effective means of ensuring bolting reliability. These programs are documented in EPRI Reports NP-5769, 1015336, and 1015337 and represent industry consensus.

Degradation-related failures have occurred in downcomer tee-quencher bolting in boiling water reactors (BWRs) designed with drywells (ADAMS Accession No. ML050730347). Leakage from bolted connections has been observed in the reactor building closed cooling systems of BWRs (Licensee Event Report 341/2005-001).

SCC of A-286 stainless steel closure bolting has occurred when seal cap enclosures have been installed to mitigate gasket leakage at valve body-to-bonnet joints (NRC Information Notice 2012-15). The enclosures surrounding the bolts filled with hot reactor coolant that had leaked from the joint and mixed with the oxygen-containing atmosphere trapped within the enclosure. The enclosures did not allow for inspections of the bolted joints.

The applicant is to evaluate applicable operating experience (OE) to support the conclusion that the effects of aging are adequately managed.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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XI.M19 STEAM GENERATORS

Program Description

The Steam Generator program is applicable to managing the aging of steam generator tubes, plugs, sleeves, divider plate assemblies, tube-to-tubesheet welds, heads (interior surfaces of channel or lower/upper heads), tubesheet(s) (primary side), and secondary side components that are contained within the steam generator (i.e., secondary side internals). The aging of steam generator pressure vessel welds is managed by other programs such as the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry."

The establishment of a steam generator program for ensuring steam generator tube integrity is required by plant technical specifications (TSs). The steam generator tube integrity portion of the TS at each pressurized water reactor (PWR) contains the same fundamental requirements as those outlined in the standard TS of NUREG–1430, Volume 1, Revision 5, for Babcock & Wilcox (B&W) PWRs; NUREG–1431, Volume 1, Revision 5, for Westinghouse PWRs; and NUREG–1432, Volume 1, Revision 5, for Combustion Engineering PWRs. The requirements pertaining to steam generators in these three versions of the standard TS are essentially identical. The TSs require tube integrity to be maintained and specify performance criteria, condition monitoring requirements, inspection scope and frequency, acceptance criteria for the plugging or repair of flawed tubes, acceptable tube repair methods, and leakage monitoring requirements.

The nondestructive examination techniques used to inspect steam generator components covered by this program are intended to identify components (e.g., tubes, plugs) that exhibit degradation and may need to be removed from service (e.g., tubes), repaired, or replaced, as appropriate.

The Steam Generator program at PWRs is modeled after Nuclear Energy Institute (NEI) 97-06, Revision 3, "Steam Generator Program Guidelines." This program references a number of industry guidelines (e.g., the Electric Power Research Institute [EPRI] PWR Steam Generator Examination Guidelines, PWR Primary-to-Secondary Leak Guidelines, PWR Primary Water Chemistry Guidelines, PWR Secondary Water Chemistry Guidelines, Steam Generator Integrity Assessment Guidelines, Steam Generator *In Situ* Pressure Test Guidelines) and incorporates a balance of prevention, mitigation, inspection, evaluation, repair, and leakage monitoring measures. The NEI 97-06 document (1) includes performance criteria that are intended to provide assurance that tube integrity is being maintained consistent with the plant's licensing basis, and (2) provides guidance for monitoring and maintaining the tubes to provide assurance that the performance criteria are met at all times between scheduled inspections of the tubes. Steam generator tube integrity can be affected by degradation of steam generator plugs, sleeves, and secondary side components. The NEI 97-06 program has been effective in managing the aging effects associated with steam generator tubes, plugs, sleeves, and secondary side components.

Degradation of divider plate assemblies, tube-to-tubesheet welds, heads (internal surfaces), or tubesheets (primary side) may have safety implications. Therefore, all of these components and the steam generator tubes, plugs, sleeves and secondary side components are addressed by this AMP.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program addresses degradation associated with steam generator tubes, plugs, sleeves, divider plate assemblies, tube-to-tubesheet welds, heads (interior surfaces of channel or lower/upper heads), tubesheet(s) (primary side), and secondary side components that are contained within the steam generator (i.e., secondary side internals). The program does not cover the steam generator secondary side shell, any nozzles attached to the secondary side shell or steam generator head, or the welds associated with these components. In addition, the program does not cover steam generator head welds other than general corrosion of these welds caused as a result of degradation (defects/flaws) in the primary side cladding.

2 ***Preventive Actions:*** This program includes preventive and mitigative actions for addressing degradation. Preventive and mitigative measures that are part of the Steam Generator program include foreign material exclusion programs and other primary and secondary side maintenance activities. The program includes foreign material exclusion as a means of inhibiting wear degradation and secondary side maintenance activities, such as sludge lancing, for removing deposits that may contribute to degradation. Guidance on foreign material exclusion is provided in NEI 97-06. Guidance on maintenance of secondary side integrity is provided in the EPRI Steam Generator Integrity Assessment Guidelines. Primary side preventive maintenance activities include replacing plugs with materials that are more resistant to stress corrosion cracking (SCC) and preventively plugging tubes susceptible to degradation.

Extensive secondary side deposit buildup in the steam generators could affect tube integrity. The EPRI Steam Generator Integrity Assessment Guidelines, which are referenced in NEI 97-06, provide guidance on maintaining the secondary side of the steam generator, including secondary side cleaning. Secondary side water chemistry plays an important role in controlling the introduction of impurities into the steam generator and potentially limiting their deposition on the tubes. Maintaining high water purity reduces susceptibility to SCC or intergranular stress corrosion cracking (IGSCC). Water chemistry is monitored and maintained in accordance with the Water Chemistry program. The program description and evaluation and technical basis of monitoring and maintaining water chemistry are addressed in the GALL-SLR Report AMP XI.M2, “Water Chemistry.”

3 ***Parameters Monitored or Inspected:*** There are currently three types of steam generator tubing used in the United States: (1) mill annealed Alloy 600, (2) thermally treated Alloy 600, and (3) thermally treated Alloy 690. Mill-annealed Alloy 600 steam generator tubes have experienced degradation due to corrosion (e.g., primary water SCC, outside diameter SCC, intergranular attack, pitting, and wastage) and mechanically induced phenomena (e.g., denting, wear, impingement damage, and fatigue). Thermally treated Alloy 600 steam generator tubes have experienced degradation due to corrosion (primarily cracking) and mechanically induced phenomena (primarily wear). Thermally treated Alloy 690 tubes have only experienced tube degradation due to mechanically induced phenomena (primarily wear).

Degradation of tube plugs, sleeves, heads, tubesheet(s), and secondary side internals has also been observed, depending, in part, on the specific component’s material of construction. The potential for degradation exists for divider plate assemblies and tube-to-tubesheet welds, depending, in part, on the components’ materials of construction. Cracking of the divider plate assemblies and the tube-to-tubesheet welds caused by PWSCC is managed by the Steam Generators and Water Chemistry programs. However, use of the One-Time Inspection AMP (beyond the Steam Generators and Water Chemistry programs) may be necessary to confirm the Steam Generators and Water Chemistry programs' effectiveness in mitigating cracking due to PWSCC. Sections 3.1.2.2.11 and 3.1.3.2.11 in NUREG-–2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants," provide the review procedures for determining whether use of the One-Time Inspection AMP is necessary.

The program includes an assessment of the forms of degradation to which a component is susceptible and implementation of inspection techniques capable of detecting those forms of degradation. The parameter monitored is specific to the component and the acceptance criteria for the inspection. For example, the severity of tube degradation may be evaluated in terms of the depth of degradation or measured voltage, depending on whether a depth-based or voltage-based tube repair criterion (acceptance criteria) is being implemented for that specific degradation mechanism. Other parameters monitored include signals of excessive deposit buildup (e.g., steam generator water level oscillations), which may result in fatigue failure of tubes or corrosion of the tubes; water chemistry parameters, which may indicate unacceptable levels of impurities; primary-to-secondary leakage, which may indicate excessive tube, plug, or sleeve degradation; and the presence of loose parts or foreign objects on the primary and secondary side of the steam generator, which may result in tube damage.

Water chemistry parameters are also monitored and controlled, as discussed in GALL-SLR Report AMP XI.M2. The EPRI PWR Primary-to-Secondary Leak Guidelines (EPRI 3002018267) provide guidance on monitoring primary-to-secondary leakage. The EPRI Steam Generator Integrity Assessment Guidelines (EPRI 3002020909) provide guidance on secondary side activities.

In summary, the NEI 97-06 program provides guidance on parameters to be monitored or inspected except for steam generator divider plate assemblies, tube-to-tubesheet welds, heads (channel or lower/upper heads), and tubesheets. For these latter components, visual inspections are performed at least every 72 effective full power months. These inspections may be performed every 96 effective full power months for units for which the technical specifications allow for extended steam generator inspection intervals. These inspections of the steam generator head interior surfaces including the divider plate are intended to identify signs that cracking or loss of material may be occurring (e.g., through identification of rust stains).

4 ***Detection of Aging Effects:*** The TSs require that a Steam Generator program be established and implemented to maintain the integrity of the steam generator tubes. In accordance with this requirement, components that could compromise tube integrity are properly evaluated or monitored (e.g., degradation of a secondary side component that could result in a loss of tube integrity is managed by this program). The inspection requirements in the TSs are intended to detect degradation (i.e., aging effects), if they occur.

The TSs are performance-based, and the actual scope of the inspection and the expansion of sample inspections are justified based on the results of the inspections. The goal is to perform inspections at a frequency sufficient to provide reasonable assurance of steam generator tube integrity for the period of time between inspections.

The general condition of some components (e.g., plugs, secondary side components, divider plates, and primary side cladding of channel heads and tubesheets) is monitored. It may be monitored visually, and, subsequently, more detailed inspections may be performed if degradation is detected.

NEI 97-06 provides additional guidance on inspection programs to detect the degradation of tubes, sleeves, plugs, and secondary side internals. The frequencies of the inspections are based on technical assessments. Guidance on performing these technical assessments is contained in NEI 97-06 and the associated industry guidelines.

The inspections and monitoring are performed by qualified personnel using qualified techniques in accordance with approved licensee procedures. The EPRI PWR Steam Generator Examination Guidelines (EPRI 3002007572) contain guidance on the qualification of steam generator tube inspection techniques.

The primary-to-secondary leakage monitoring program provides a potential indicator of a loss of steam generator tube integrity. NEI 97-06 and the associated EPRI guidelines provide information pertaining to an effective leakage monitoring program.

5 ***Monitoring and Trending:*** Condition monitoring assessments are performed to determine whether the structural- and accident-induced leakage performance criteria were satisfied during the prior operating interval. Operational assessments are performed to verify that structural and leakage integrity will be maintained for the planned operating interval before the next inspection. If tube integrity cannot be maintained for the planned operating interval before the next inspection, corrective actions are taken in accordance with the plant's corrective action program. Comparisons of the results of the condition monitoring assessment to the predictions of the previous operational assessment are performed to evaluate the adequacy of the previous operational assessment methodology. If the operational assessment was not conservative in terms of the number and/or severity of the condition, corrective actions are taken in accordance with the plant's corrective action program.

The TSs require condition monitoring and operational assessments to be performed (although the TSs do not explicitly require operational assessments, these assessments are necessary to ensure that the tube integrity will be maintained until the next inspection). Condition monitoring and operational assessments are done in accordance with the TS requirements and guidance in NEI 97-06 and the EPRI Steam Generator Integrity Assessment Guidelines.

The goal of the inspection program for all components covered by this AMP is to ensure that the components continue to function consistent with the design and licensing basis of the facility (including regulatory safety margins).

Assessments of the degradation that may occur in the components covered by this AMP, except for steam generator divider plate assemblies, tube-to-tubesheet welds, heads, and tubesheets as noted above, are performed in accordance with the guidance in the EPRI Steam Generator Integrity Assessment Guidelines. All assessments of component degradation are performed to confirm that the components continue to function consistent with the design and licensing basis and to confirm that TS requirements are satisfied.

6 ***Acceptance Criteria:*** Assessment of tube and sleeve integrity and plugging or repair criteria of flawed and sleeved tubes is in accordance with plant TSs. The criteria for plugging or repairing steam generator tubes and sleeves are based on the U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.121 and are incorporated into plant TSs. Guidance on assessing the acceptability of flaws is also provided in NEI 97-06 and the associated EPRI guidelines, including the EPRI Pressurized Water Reactor Steam Generator Examination Guidelines (EPRI 3002007572), EPRI Steam Generator *In-Situ* Pressure Test Guidelines (EPRI 3002007856) and EPRI Steam Generator Integrity Assessment Guidelines (EPRI 3002020909).

Degraded plugs, divider plate assemblies, tube-to-tubesheet welds, heads (interior surfaces), tubesheets (primary side), and secondary side internals are evaluated for continued acceptability on a case-by-case basis, as is done for leaving a loose part or a foreign object in a steam generator. NEI 97-06 and the associated EPRI guidelines provide guidance on the performance of some of these evaluations. The intent of all evaluations is to ensure that the components will continue to perform their functions consistent with the design and licensing basis of the facility and will not affect the integrity of other components (e.g., by generating loose parts).

Guidance on the acceptability of primary-to-secondary leakage and water chemistry parameters also is discussed in NEI 97-06 and the associated EPRI guidelines.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

For degradation of steam generator tubes and sleeves (if applicable), the TSs provide requirements for the actions to be taken when the acceptance criteria are not met. For degradation of other components, the appropriate corrective action is evaluated per NEI 97-06 and the associated EPRI guidelines, the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Section XI,[1] 10 CFR 50.65, and 10 CFR Part 50, Appendix B, as appropriate.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

The adequacy of the preventive measures in the Steam Generator program is confirmed through periodic inspections.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Several generic communications related to the steam generator programs implemented at plants have been issued by the NRC. The reference section lists many of these generic communications. In addition, NEI 97-06 provides guidance to the industry for routinely sharing pertinent steam generator operating experience (OE) and for incorporating lessons learned from plant operation into guidelines referenced in NEI 97-06. The latter includes providing interim guidance to the industry, when needed.

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

The NEI 97-06 program has been effective at managing the aging effects associated with steam generator tubes, plugs, sleeves, and secondary side components that are contained within the steam generator (i.e., secondary side internals), such that the steam generators can perform their intended safety function.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

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XI.M20 OPEN-CYCLE COOLING WATER SYSTEM

Program Description

This program relies, in part, on implementing portions of the recommendations of the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-13 to provide reasonable assurance that the effects of aging on the open-cycle cooling water (OCCW; or service water) system will be managed for the subsequent period of extended operation. NRC GL 89-13 defines the OCCW system as a system or systems that transfer heat from safety-related systems, structures, and components (SSCs) to the ultimate heat sink. The program comprises the aging management aspects of the applicant's response to NRC GL 89-13 including (1) a program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling; (2) a program to verify heat transfer capabilities of all safety-related heat exchangers cooled by the OCCW system; and (3) a program for routine inspection and maintenance to provide reasonable assurance that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of safety-related systems serviced by the OCCW system. Because the guidance in NRC GL 89-13 was not specifically developed to address aging management, this program includes enhancements to the guidance in NRC GL 89-13 that address operating experience (OE) to provide reasonable assurance that aging effects are adequately managed.

The OCCW system program manages the aging effects of components in raw water systems, such as service water, by using a combination of preventive, condition monitoring, and performance monitoring activities. These activities include (1) surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, and fouling in the OCCW system or structures and components (SCs) serviced by the OCCW system; (2) inspection of components for signs of loss of material, corrosion, erosion, cracking, fouling, and biofouling; and (3) testing of the heat transfer capability of heat exchangers that remove heat from components important to safety.

For buried OCCW system piping, the aging effects on the external surfaces are managed by the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M41, "Buried and Underground Piping and Tanks," but the internal surfaces are managed by this program. AMP XI.M43, "High Density Polyethylene (HDPE) and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping," manages the internal and external surfaces of HDPE and CFRP repaired piping. The aging management of closed-cycle cooling water systems is described in AMP XI.M21A, "Closed Treated Water Systems," and is not included as part of this program. Service water system components or components in other raw water systems that are not included within the scope of GL 89-13 may be managed by AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." However, water systems for fire protection are managed by AMP XI.M27, "Fire Water System." If the OCCW system program manages loss of coating integrity for internal coatings or linings, the program includes the guidance provided in the "scope of program" program element of AMPXI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks."

Evaluation and Technical Basis

1 ***Scope of Program:*** This program addresses piping, piping components, piping elements, and heat exchanger components exposed to raw water in the OCCW system. The program applies to components constructed of various materials including steel, stainless steel (SS), aluminum, copper alloys, titanium, nickel alloy, fiberglass, polymeric materials, and concrete. The program may manage loss of coating integrity as provided in the recommendations of AMP XI.M42. This program references NRC GL 89-13; plant activities in response to NRC GL 89-13 may be credited for this program, as appropriate.

2 ***Preventive Actions:*** This program is primarily a condition monitoring program, but some preventive actions may be effective. Implementation of NRC GL 89-13 includes control techniques, such as chemical treatment whenever the potential for biofouling exists. Treatment with chemicals mitigates microbiologically influenced corrosion (MIC) and buildup of macroscopic biofouling debris from biota such as blue mussels, oysters, or clams. Periodic flushing of infrequently used cooling loops removes accumulations of biofouling agents, corrosion products, debris, and silt. The use of degradation-resistant materials and the application of internal coatings or linings may be included.

3 ***Parameters Monitored or Inspected:*** This program addresses loss of material, reduction of heat transfer, flow blockage, and in some materials, cracking. The program (1) inspects the surfaces of components exposed to raw water for the presence of fouling; (2) monitors the heat transfer performance of components affected by fouling in the OCCW system; and (3) monitors the condition of piping and components to provide reasonable assurance that loss of material, loss of coating or lining integrity (when this program is used in lieu of AMP XI.M42), cracking, and flow blockage do not degrade the performance of the safety-related systems supplied by the OCCW system. For the portions of the OCCW system for which flow monitoring is not performed, test results from the monitored portions of the system are used to calculate friction (or roughness) factors, which are used to confirm that design flow rates will be achieved with the overall fouling identified in the system. If the aging effects associated with concrete piping are being managed, American Concrete Institute (ACI) 349.3R and ACI 201.R1 provide acceptable bases for parameters monitored or inspected.

4 ***Detection of Aging Effects:*** Inspection scope, methods (e.g., visual or volumetric inspections, performance testing), and frequencies are in accordance with the applicant’s docketed response to NRC GL 89-13. As noted in NRC GL 89-13, testing frequencies can be adjusted to provide assurance that equipment will perform its intended function between test intervals, but should not exceed 5 years. Visual inspections are used to identify fouling and loss of coating or lining integrity (when this program is used in lieu of AMP XI.M42), and provide a qualitative assessment for loss of material due to various forms of corrosion and erosion. Examinations of polymeric and concrete materials should be consistent with the examinations described in AMP XI.M38. Volumetric examinations, such as ultrasonic testing, eddy current testing, and radiography are used to quantify the extent of wall thinning or loss of material.

Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) should follow procedures consistent with the ASME Code. Non-ASME Code inspections follow site procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. For concrete components, the qualifications of personnel performing inspections and evaluations are specified in ACI 349.3R.

5 ***Monitoring and Trending:*** For heat exchangers that are tested for heat transfer capability, test results are trended to verify the adequacy of the testing frequencies. For heat exchangers that are inspected for degradation in lieu of testing, inspection results are trended to evaluate the adequacy of the inspection frequencies. If fouling is identified, the system is evaluated for the impact on the heat transfer capability of the system. Friction (or roughness) factors are trended to confirm design flow rates can be achieved in the portions of the OCCW system in which flow monitoring is not performed. Evidence of corrosion is evaluated for its potential impact on the integrity of the piping. For ongoing degradation due to specific aging mechanisms (e.g., MIC), the program includes trending of wall thickness measurements at susceptible locations to adjust the monitoring frequency and the number of inspection locations.

6 ***Acceptance Criteria:*** Predicted wall thicknesses at the time of the next scheduled inspection are greater than the components' minimum wall thickness requirements. As applicable, coatings or linings meet the acceptance criteria from AMP XI.M42. For heat exchangers, heat removal capability is within design values. For ongoing degradation mechanisms (e.g., MIC), the program includes criteria for the extent or rate of degradation that will prompt more comprehensive corrective actions. If concrete piping is being managed, acceptance criteria are derived from ACI 349.3R, as applicable.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

The program includes reevaluation, repair, or replacement of components that do not meet minimum wall thickness requirements. If fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, loss of material, and (if applicable) chemical treatment effectiveness. For ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections are increased commensurate with the significance of the degradation.

If the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement of all components constructed of the same material and exposed to the same environment, additional inspections are conducted if one of the inspections does not meet the acceptance criteria. The number of increased inspections is determined in accordance with the site's corrective action program; however, no fewer than five additional inspections are conducted for each inspection that did not meet the acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. At multi-unit sites, the additional inspections include inspections at all of the units that have the same material, environment, and aging effect combination.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Loss of material due to corrosion, including MIC and erosion, has been identified (NRC Information Notice [IN] 85-30, IN 2007-06, Licensee Event Reports [LER] 247/2001-006, LER 306/2004-001, LER 483/2005-002, LER 331/2006-003, LER 255/2007-002, LER 454/2007-002, LER 254/2011-001, LER 255/2013-001, LER 286/2014-002). Protective coatings have failed, leading to unanticipated corrosion (IN 85-24, IN 2007-06, LER 286/2002-001, LER 286/2011-003). Reduction of heat transfer and flow blockage due to fouling has occurred in piping and in heat exchangers as a result of protective coating failures, and accumulations of silt and sediment (IN 81-21, IN 86-96, IN 2004-07, IN 2006-17, IN 2007-28, IN 2008-11, LER 413/1999-010, LER 305/2000-007, LER 266/2002-003, LER 413/2003-004, LER 263/2007-004, LER 321/2010-002, LER 457/2011-001, LER 457/2011-002, LER 397/2013-002). Cracking due to stress corrosion cracking has occurred in brass tubing (LER 305/2002-002), and pitting in SS has occurred (LER 247/2013-004).

The review of plant-specific OE during the development of this program is to be broad and sufficiently detailed to detect instances of aging effects that have repeatedly occurred. In some instances, recurring internal corrosion may warrant program enhancements. Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR) Sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6, “Loss of Material Due to Recurring Internal Corrosion,” include criteria for identifying instances of recurring internal corrosion and recommendations for augmenting aging management activities.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

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XI.M21

XI.M21A CLOSED TREATED WATER SYSTEMS

Program Description

Nuclear power plants contain many closed, treated water systems. These systems undergo water treatment to control water chemistry and prevent corrosion (i.e., treated water systems). These systems are also recirculating systems in which the rate of recirculation is much higher than the rate of the addition of makeup water (i.e., closed systems). This is a mitigation program that also includes condition monitoring to verify the effectiveness of the mitigation activities. The program includes (1) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; (2) chemical testing of the water to demonstrate that the water treatment program maintains the water chemistry within acceptable guidelines; and (3) inspections to determine the presence or extent of degradation. Depending on the water treatment program selected for use in association with this aging management program (AMP) and/or plant operating experience (OE), this program also may include corrosion monitoring (e.g., corrosion coupon testing) and microbiological testing.

The water used in systems covered by this AMP may be, but need not be, demineralized and receives chemical treatment, including corrosion inhibitors, unless the systems meet the industry guidance for pure water systems. Otherwise, untreated water systems are addressed using other AMPs, such as Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (XI.M38). Examples of systems managed by this AMP include closed-cycle cooling water (CCCW) systems (as defined by the U.S. Nuclear Regulatory Commission [NRC] Generic Letter [GL] 89-13[1]); closed portions of heating, ventilation, and air conditioning systems; and diesel generator cooling water. Examples of systems not addressed by this AMP include systems containing boiling water reactor (BWR) coolant, pressurized water reactor (PWR) primary and secondary water, and PWR/BWR condensate that does not contain corrosion inhibitors. Aging in these systems is managed by the water chemistry AMP (XI.M2) and the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD AMP (XI.M1).[2] Treated fire water systems, if present, are also not included in this AMP.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages the aging effects of loss of material due to corrosion, cracking due to stress corrosion cracking (SCC), and reduction of heat transfer due to fouling of the internal surfaces of piping, piping components, piping elements and heat exchanger components fabricated from any material and exposed to treated water.

2 ***Preventive Actions:*** This program mitigates the aging effects of loss of material, cracking, and reduction of heat transfer through water treatment. The water treatment program

[1] NRC GL 89-13 defines a service water system as “the system or systems that transfer heat from safety-related structures, systems, or components to the ultimate heat sink.” NRC GL 89-13 further defines a closed-cycle system as a part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled and in which heat is not directly rejected to an ultimate heat sink.

[2] Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

includes corrosion inhibitors and is designed to maintain the function of associated equipment and minimize the corrosivity of the water and the accumulation of corrosion products that can foul heat transfer surfaces.

3 ***Parameters Monitored or Inspected:*** This program monitors water chemistry parameters (preventive monitoring) and the condition of surfaces exposed to the water (condition monitoring). Depending on the water treatment program selected for use in association with this AMP and/or plant OE, this program may also include corrosion monitoring (e.g., corrosion coupon testing) and microbiological testing.

Water chemistry parameters (such as the concentration of iron, copper, silica, oxygen, and hardness, alkalinity, specific conductivity, and pH) are monitored because maintenance of optimal water chemistry prevents loss of material and cracking due to corrosion and SCC. The specific water chemistry parameters monitored and the acceptable range of values for these parameters are in accordance with the Electric Power Research Institute (EPRI) 3002000590 V“Closed Cooling Water Chemistry Guideline,” which is used in its entirety for the water chemistry control or guidance.

The visual appearance of surfaces is evaluated for evidence of loss of material. The results of surface or volumetric examinations are evaluated for surface discontinuities indicative of cracking. The heat transfer capability of heat exchanger surfaces is evaluated by either visual inspections to determine surface cleanliness, or by functional testing to verify that design heat removal rates are maintained.

4 ***Detection of Aging Effects:*** In this program, aging effects are detected through water testing and periodic inspections. Water testing determines whether the water treatment program effectively maintains acceptable water chemistry. Water testing frequency is conducted in accordance with the selected water treatment program.

Because the control of water chemistry may not be fully effective in mitigating the aging effects, inspections are conducted. Visual inspections of internal surfaces are conducted whenever the system boundary is opened. At a minimum, during each 10-year period of the subsequent period of extended operation, a representative sample of 20 percent of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of 25 components per population at each unit is inspected using techniques capable of detecting loss of material, cracking, and fouling, as appropriate. The 20 percent minimum is surface area inspected unless the component is measured in linear feet, such as piping. In that case, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. <u>Samples are taken from multiple locations to ensure that a representative sample is examined, focusing on components most susceptible to the applicable aging effect.</u> Technical justification for an alternative sampling methodology is included in the program’s documentation. For multi-unit sites where the sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections at the site as follows. For two-unit sites, 19 components are inspected per unit and for a three-unit site, 17 components are inspected per unit. To conduct 17 or 19 inspections at a unit in lieu of 25, the subsequent license renewal application includes the basis for why the operating conditions at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) to provide representative inspection results. The basis should include consideration of potential differences such as the following:

- Have power uprates been performed and, if so, could more aging have occurred on one unit that has been in the uprate period for a longer time period?

- Have any systems had an out-of-spec water chemistry condition for a longer period of time or out-of-spec conditions that occurred more frequently?
- If degradation is identified in the initial sample, additional samples are inspected to determine the extent of the condition.

The ongoing opportunistic visual inspections are credited toward the representative samples for the loss of material and fouling; however, surface or volumetric examinations are used to detect cracking. The inspections focus on the components most susceptible to aging because of time in service and severity of operating conditions, including locations where local conditions may be significantly more severe than those in the bulk water (e.g., heat exchanger tube surfaces).

Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code should follow procedures consistent with the ASME Code. Non-ASME Code inspections follow site procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

5 ***Monitoring and Trending:*** Water chemistry data are evaluated against the standards contained in the selected water treatment program. These data are trended, so corrective actions are taken, based on trends in water chemistry, prior to loss of intended functions. Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

6 ***Acceptance Criteria:*** Water chemistry concentrations are maintained within the limits specified in the selected industry standard documents. Due to the water chemistry controls, no age-related degradation is expected. Therefore, any detectable loss of material, cracking, or fouling is evaluated in the corrective action program.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Water chemistry concentrations that are not in accordance with the selected water treatment program should be returned to the normal operating range within the prescribed timeframe for each action level. If fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, and loss of material.

If the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement of all components constructed of the same material and exposed to the same environment, additional inspections are conducted if one of the inspections does not meet the acceptance criteria. The number of increased inspections is determined in accordance with the site's corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet the acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. If subsequent inspections do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections needed. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. At multi-unit sites, the additional inspections include inspections at all of the units that have the same material, environment, and aging effect combination. The additional inspections are completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Degradation of CCCW systems due to corrosion product buildup (Licensee Event Report [LER] 327/1993-029) or through-wall cracks in supply lines (LER 280/1991-019) has been observed in operating plants. In addition, SCC of stainless steel reactor recirculation pump seal heat exchanger coils has been attributed to localized boiling of the closed cooling water, concentrating water impurities on the coil surfaces (LER 263/2014-001). Accordingly, OE demonstrates the need for this program.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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XI.M22 BORAFLEX MONITORING

Program Description

Many neutron-absorbing materials, such as Boraflex, Boral®, Metamic, boron steel, and carborundum, are used in spent fuel pools. This aging management program (AMP) addresses the aging management of spent fuel pools using Boraflex as the neutron-absorbing material. Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M40, "Monitoring of Neutron-Absorbing Material Other Than Boraflex," addresses aging management of spent fuel pools using neutron-absorbing materials other than Boraflex, such as Boral, Metamic, boron steel, and carborundum. When a spent fuel pool criticality analysis credits Boraflex and materials other than Boraflex, the guidance in both GALL-SLR Report AMPs XI.M22 and XI.M40 applies.

For Boraflex panels in spent fuel storage racks, gamma irradiation and long-term exposure to the wet fuel pool environment cause shrinkage resulting in gap formation, gradual degradation of the polymer matrix, and the release of silica to the spent fuel storage pool water. This results in the loss of boron carbide in the neutron absorber sheets. A monitoring program for the Boraflex panels in the spent fuel storage racks is implemented to assure that no unexpected degradation of the Boraflex material compromises the criticality analysis in support of the design of spent fuel storage racks. This AMP relies on periodic inspection, testing, monitoring, and analysis of the criticality design to assure that the required 5 percent subcriticality margin is maintained. Therefore, this AMP includes (1) completing sampling and analysis for silica levels in the spent fuel pool water on a regular basis, such as monthly, quarterly, or annually (depending on Boraflex panel condition), and trending the results by using the Electric Power Research Institute (EPRI) RACKLIFE predictive code or its equivalent; and (2) performing neutron attenuation testing to determine gap formation in Boraflex panels or measuring boron-10 areal density by techniques such as the BADGER device.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages the effect of reduction in neutron-absorbing capacity due to degradation in sheets of neutron-absorbing material made of Boraflex affixed to spent fuel racks.

2 ***Preventive Actions:*** This program is a performance monitoring program and does not include preventive actions.

3 ***Parameters Monitored or Inspected:*** The parameters monitored include the physical conditions of the Boraflex panels, such as gap formation and decreased boron-10 areal density, and the concentration of the silica in the spent fuel pool. These are conditions directly related to degradation of the Boraflex material. When Boraflex is subjected to gamma radiation and long-term exposure to the spent fuel pool environment, the silicon polymer matrix becomes degraded and silica filler and boron carbide are released into the spent fuel pool water. As indicated in the U.S. Nuclear Regulatory Commission (NRC) Information Notice (IN) 95-38 and NRC Generic Letter (GL) 96-04, the loss of boron carbide (washout) from Boraflex is characterized by slow dissolution of silica from the surface of the Boraflex and a gradual thinning of the material. Because Boraflex contains about 25 percent silica, 25 percent polydimethyl siloxane polymer, and 50 percent boron carbide, sampling and analysis for the presence of silica in the spent fuel pool provide an indication of the depletion of boron carbide from Boraflex; however, the degree to which Boraflex has degraded is ascertained through measurement of the boron-10 areal density.

4 ***Detection of Aging Effects:*** Aging effects on Boraflex panels are detected by monitoring silica levels in the spent fuel storage pool on a regular basis, such as monthly, quarterly, or annually (depending on Boraflex panel condition); by measuring boron-10 areal density on a frequency determined by the material condition of the Boraflex panels, with a minimum frequency of once every 5 years; and by applying predictive methods to the measured results. The amount of boron-10 carbide present in the Boraflex panels is determined through direct measurement of boron-10 areal density by periodic verification of boron-10 loss through areal density measurement techniques, such as the BADGER device. Frequent Boraflex testing is sufficient to verify that Boraflex panel degradation does not compromise the criticality analysis of the spent fuel pool storage racks. Additionally, changes in the level of silica present in the spent fuel pool water provide an indication of changes in the rate of degradation of Boraflex panels.

5 ***Monitoring and Trending:*** The periodic inspection measurements and analysis are compared to values of previous measurements and analysis providing a continuing level of data for trend analysis. Sampling and analysis for silica levels in the spent fuel pool water is performed on a regular basis, such as monthly, quarterly, or annually (depending on Boraflex panel condition), and the results are trended using the EPRI RACKLIFE predictive code or its equivalent. Silica concentration is monitored against time to trend degradation. Rapid increases of silica concentration may indicate accelerated Boraflex degradation. The frequency of performing boron-10 areal density testing will be determined by the material condition of the Boraflex panels, with an interval not to exceed 5 years.

6 ***Acceptance Criteria:*** The 5 percent subcriticality margin of the spent fuel racks is maintained for the subsequent period of extended operation.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Corrective actions are initiated if the test results find that the 5 percent subcriticality margin cannot be maintained because of the current or projected future degradation. Corrective actions consist of providing additional neutron-absorbing capacity by Boral or boron steel inserts or other options that are available to maintain a subcriticality margin of 5 percent.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative

controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** NRC IN 87-43 addresses the problems of development of tears and gaps (average 1–2 inches, with the largest being 4 inches) in Boraflex sheets due to gamma radiation-induced shrinkage of the material. NRC IN 93-70, NRC IN 95-38, and NRC GL 96-04 address several cases of significant degradation of Boraflex test coupons due to accelerated dissolution of Boraflex caused by pool water flow through panel enclosures and high accumulated gamma dose. In such cases, the Boraflex may be replaced by boron steel inserts or by a completely new rack system using Boral. Experience with boron steel is limited; however, the application of Boral for use in the spent fuel storage racks predates the manufacturing and use of Boraflex. The experience with Boraflex panels indicates that coupon surveillance programs are not reliable. Therefore, during the subsequent period of extended operation, the measurement of boron-10 areal density correlated, through a predictive code, with silica levels in the pool water, is verified. These monitoring programs provide assurance that degradation of Boraflex sheets is monitored so that appropriate actions can be taken in a timely manner if significant loss of neutron-absorbing capability is occurring. These monitoring programs provide reasonable assurance that the Boraflex sheets maintain their integrity and are effective in performing their intended function.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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_____. Information Notice 87-43, “Gaps in Neutron Absorbing Material in High Density Spent Fuel Storage Racks.” ADAMS Accession No. ML031130349. Washington, DC: U.S. Nuclear Regulatory Commission. September 8, 1987.

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XI.M23 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

Program Description

This program evaluates the effectiveness of maintenance monitoring activities for cranes and hoists that are within the scope of license renewal. This program addresses the inspection and monitoring of crane-related structures and components to provide reasonable assurance that the handling system does not affect the intended function of nearby safety-related equipment. Many crane systems and components are not within the scope of this program because they perform an intended function with moving parts or with a change in configuration, or they are subject to replacement based on qualified life.

The program includes periodic visual inspections to detect loss of material due to general corrosion and wear, deformed or cracked bridges, structural members, and structural components; and loss of material due to general corrosion, cracking, and loss of preload on bolted connections. NUREG–0612, “Control of Heavy Loads at Nuclear Power Plants,” provides specific guidance on the control of overhead heavy load cranes. The activities to manage aging effects specified in this program use the guidance provided in American Society of Mechanical Engineers (ASME) Safety Standard B30.2, “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist),” which is referenced by NUREG–0612, or other appropriate standards in the ASME B30 series. In addition, monitoring and maintenance of structural components of crane handling systems follow the maintenance rule requirements provided in Title 10 of the *Code of Federal Regulations* (10 CFR) 50.65 for other crane types.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages the aging effects associated with handling systems that are within the scope of 10 CFR 54.4 (TN4878). Portions of the handling system that are within the scope of this program include the bridges, structural members, and structural components.

2 ***Preventive Actions:*** This program is a condition monitoring program. No preventive actions are identified.

3 ***Parameters Monitored or Inspected:*** Surface condition is monitored by visual inspection to provide reasonable assurance that loss of material is not occurring due to general corrosion or wear, and the bridges, structural members, and structural components do not exhibit deformation or cracking. In addition, bolted connections are monitored for loss of material, cracking, and loose bolts, missing or loose nuts, and other conditions indicative of loss of preload.

4 ***Detection of Aging Effects:*** Load handling systems are visually inspected at a frequency in accordance ASME B30.2, “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist),” or another appropriate standard in the ASME B30 series. ASME B30.2 establishes inspection frequencies based on the severity of service, as defined by the number and magnitude of lifts. For systems that are infrequently in service, such as containment polar cranes, periodic inspections are performed once every refueling cycle just prior to use. Visual inspections consist of the following:

- Bridges, structural members, and structural components are visually inspected for loss of material due to general corrosion; deformation; cracking, and wear.

- Bolted connections are visually inspected for loss of material due to general corrosion; cracking; and loose or missing bolts or nuts, and other conditions indicative of loss of preload.

Visual inspection activities are performed by personnel qualified in accordance with plant-specific procedures and processes.

5 ***Monitoring and Trending:*** Deficiencies are documented using plant-specific processes and procedures, such that results can be trended; however, the program does not include formal trending.

6 ***Acceptance Criteria:*** Any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload is evaluated according to ASME B30.2 or another applicable industry standard in the ASME B30 series.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Repairs are performed as specified in ASME B30.2 or another appropriate standard in the ASME B30 series.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** There has been no history of corrosion-related degradation that threatened the ability of a crane to perform its intended function. Likewise, because cranes have not been operated beyond their design lifetimes, there have been no significant fatigue-related structural failures. Operating experience indicates that loss of bolt preload has occurred, but not to the extent that it has threatened the ability of a crane structure to perform its intended function.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 54.4, “Scope.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015. 10 CFR Part 54-TN4878

ASME. Safety Standard B30.2, “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist).” New York, New York: American Society of Mechanical Engineers. 2005.

NRC. Generic Letter 80-113, “Control of Heavy Loads.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML071080219. Washington, DC: U.S. Nuclear Regulatory Commission. December 22, 1980.

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_____. Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” Revision 2. ADAMS Accession No. ML003761662. U.S. Nuclear Regulatory Commission, March 31, 1997.

XI.M24 COMPRESSED AIR MONITORING

Program Description

This program provides reasonable assurance of the integrity of the compressed air system downstream of the instrument air dryers. The program consists of monitoring the moisture content, corrosion, and performance of the compressed air system. This includes (1) preventive monitoring of water (moisture) and other potentially corrosive contaminants to keep within the specified limits; and (2) opportunistic inspection of components for indications of loss of material due to corrosion.

This aging management program (AMP) does not change the applicant's docketed response to U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-14 for the rest of its operations. The AMP also incorporates the air quality provisions provided in the guidance of Electric Power Research Institute (EPRI) TR-108147. The American Society of Mechanical Engineers (ASME) operations and maintenance standards and guides (ASME OM-2012, Division 2, Part 28) provide additional guidance for maintenance of the instrument air system by offering recommended test methods, test intervals, parameters to be measured and evaluated, and records requirements.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages the aging effects of loss of material due to corrosion in compressed air system components located downstream of the compressed air system air dryers, or for components exposed to an internal gas environment (e.g., nitrogen-filled accumulators). Aging effects associated with components located upstream of the air dryers, or those exposed to an air environment that is not subject to the preventive actions of this program, are managed by Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components."

2 ***Preventive Actions:*** For the purposes of aging management, moisture and other corrosive contaminants in the system's air are maintained below specified limits to provide reasonable assurance that the system and components maintain their intended functions. These limits are prepared based on consideration of the manufacturer's recommendations for individual components and guidelines based on ASME OM-2012, Division 2, Part 28; ANSI/ISA-7.0.01-1996; and EPRI TR–108147.

3 ***Parameters Monitored or Inspected:*** Periodic air samples are taken and analyzed for moisture content and corrosive contaminants. Opportunistic visual inspections of accessible internal surfaces are performed for signs of corrosion and abnormal corrosion products that might indicate a loss of material within the system.

4 ***Detection of Aging Effects:*** The program periodically samples and tests the air in the compressed system in accordance with industry standards (i.e., ANSI/ISA-7.0.01-1996). Compressed air systems have in-line dew point instrumentation that either continuously monitors using an automatic alarm system or is checked at least daily to determine whether the moisture content is within the recommended range. Additionally, opportunistic visual inspections of component internal surfaces exposed to an air-dry environment are performed for signs of loss of material due to corrosion. Guidance for inspection frequency and inspection methods related to these components is provided in standards or documents such as ASME OM-2012, Division 2, Part 28.

Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task.

5 ***Monitoring and Trending:*** If daily readings of system dew points are taken, they are recorded and trended. Air quality analysis results are reviewed to determine whether alert levels or limits have been reached or exceeded. This review also checks for unusual trends. ASME OM-2012, Division 2, Part 28, provides guidance for monitoring and trending data. The effects of corrosion are monitored by visual inspection. Test data are analyzed and compared to data from previous tests to provide for the timely detection of aging effects on passive components.

6 ***Acceptance Criteria:*** Acceptance criteria for air quality moisture limits are established based on accepted industry standards, such as American National Standards Institute/International Society of Automation (ANSI/ISA)-7.0.01-1996. Internal surfaces do not show signs of corrosion (general, pitting, and crevice) that could indicate the potential loss of function of the component. Suppliers' certifications can be used to demonstrate that bottled gases meet acceptable quality standards.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Corrective actions are taken if any parameters, such as moisture content in the system air, are out of acceptable ranges, or if corrosion is identified on internal surfaces.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Potentially significant safety-related problems pertaining to air systems have been documented in NRC Information Notice (IN) 81-38, IN 87-28, IN 87-28, Supplement 1, and in Licensee Event Report 237/94-005-3. Some of the systems that have been significantly degraded or that have failed due to the problems in the air system include the decay heat removal, auxiliary feedwater, main steam isolation, containment isolation, and fuel pool seal systems. In 2008, one plant incurred an unplanned reactor trip from a failure of a mechanical joint in the instrument air system (NRC IN 2008-06). Nevertheless, as a result of NRC GL 88-14 and in consideration of Institute of Nuclear Power Operations Significant Operating Experience Report (INPO SOER) 88-01 and EPRI TR–108147, performance of air systems has improved significantly.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016.

ANSI. ANSI/ISA-7.0.01-1996, “Quality Standard for Instrument Air.” Washington, DC: American National Standards Institute. 1996.

ASME. ASME OM-2012, “Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants.” Division 2, Part 28. New York, New York: American Society of Mechanical Engineers. 2012.

EPRI. EPRI TR–108147, “Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079.” Palo Alto, California: Electric Power Research Institute. March 1998.

INPO. INPO Significant Operating Experience Report 88-01, “Instrument Air System Failures.” Atlanta, Georgia: Institute of Nuclear Power Operations. May 1988.

Licensee Event Report 237/94-005-3, “Manual Reactor Scram due to Loss of Instrument Air Resulting from Air Receiver Pipe Failure Caused by Improper Installation of Threaded Pipe during Initial Construction.” https://lersearch.inl.gov/LERSearchCriteria.aspx. April 3, 1997.

NRC. Generic Letter 88-14, “Instrument Air Supply Problems Affecting Safety-Related Components.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML031130440. Washington, DC: U.S. Nuclear Regulatory Commission. August 8, 1988.

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_____. Information Notice 2008-06, “Instrument Air System Failure Resulting In Manual Reactor Trip.” ADAMS Accession No. ML073540243. Washington, DC: U.S. Nuclear Regulatory Commission. April 10, 2008.

XI.M25 BWR REACTOR WATER CLEANUP SYSTEM

Program Description

This program is a condition monitoring program that provides inspections to manage cracking due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) on the intended function of certain austenitic stainless steel (SS) piping in the reactor water cleanup (RWCU) system of boiling water reactors (BWRs). Based on the U.S. Nuclear Regulatory Commission (NRC) criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG–0313, Revision 2, and NRC Generic Letter (GL) 88-01 and its Supplement 1.

NRC GL 88-01 applies to all BWR piping made of austenitic SS that is 4 inches or larger in nominal diameter and contains reactor coolant at a temperature above 93 °C (Celsius; 200 °F [Fahrenheit]) during power operation, regardless of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) classification. NRC GL 88-01 requests, in part, that affected licensees implement an inservice inspection (ISI) program conforming to staff positions for austenitic SS piping covered under the scope of the letter. In response to NRC GL 88-01, affected licensees undertook ISI in accordance with the scope and schedules described in the letter and included affected portions of RWCU piping outboard of the second isolation valves within their ISI programs.

The NRC issued GL 88-01, Supplement 1, to provide acceptable alternatives to the staff positions delineated in NRC GL 88-01. In NRC GL 88-01, Supplement 1, the staff noted, in part, that the position stated in NRC GL 88-01 about the inspection sample size of RWCU system welds outboard of the second isolation valves had created an unnecessary hardship for affected licensees because of the very high radiation levels associated with this portion of RWCU piping. The staff also noted that affected licensees had requested that they be exempted from NRC GL 88-01 with regard to inspection of this piping of the RWCU system. Although NRC GL 88-01, Supplement 1, does not provide explicit generic guidance with regard to staff criteria for reduction or elimination of RWCU weld inspections, it does suggest that the staff would be receptive to modifications to a licensee's original docketed NRC GL 88-01 response for RWCU weld inspections, if all issues of reactor safety were adequately addressed. The staff has subsequently allowed individual licensees to modify their docketed responses to GL-88-01 to reduce or eliminate their ISI of RWCU welds in the piping outboard of the second isolation valves. This program only applies in cases where the NRC has not previously approved the complete elimination of the augmented GL 88 01 inspections for RWCU system piping outboard the second containment isolation valves.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program provides ISI to manage cracking due to SCC or IGSCC in austenitic SS piping outboard of the second containment isolation valves in the RWCU system.

The components included in this program are the welds in piping that have a nominal diameter of 4 inches or larger and that contain reactor coolant at a temperature above 93 °C (Celsius; 200 °F [Fahrenheit]) during power operation, regardless of ASME Code classification.

2 ***Preventive Actions:*** The comprehensive program outlined in NUREG–0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause

SCC or IGSCC. These elements are a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. The program delineated in NUREG–0313 and NRC GL 88-01 includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. The resistant materials are used for new and replacement components and include low-carbon grades of austenitic SS and weld metal, with a maximum carbon of 0.035 weight percent and a minimum ferrite of 7.5 percent in weld metal and cast austenitic stainless steel. Special processes are used for existing, new, and replacement components. These processes include solution heat treatment, heat sink welding, induction heating, and mechanical stress improvement. Reactor coolant water chemistry is monitored and maintained in accordance with activities that meet the guidelines in the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M2, “Water Chemistry.”

3 ***Parameters Monitored or Inspected:*** The aging management program (AMP) monitors SCC or IGSCC of austenitic SS piping by detecting and sizing cracks in accordance with the guidelines of NUREG–0313, NRC GL 88-01, and NRC GL 88-01, Supplement 1.

4 ***Detection of Aging Effects:*** The extent, method, and schedule of the inspections delineated in the NRC inspection criteria for RWCU piping and NRC GL 88-01 are designed to maintain structural integrity and to detect aging effects before the loss of intended function of austenitic SS piping and fittings. Guidelines for the inspection schedule, methods, personnel, and sample expansion are based on NRC GL 88-01 and GL 88-01, Supplement 1, and any applicable alternatives to these inspections that were subsequently approved by the NRC. These alternative inspections are implemented in accordance with the current licensing basis for the plant. Typically, if all of the GL 89-10 actions had not been satisfactorily completed, then one alternative inspection would include 10 percent of the welds every refueling outage. Another alternative inspection would typically include at least 2 percent of the welds or 2 welds every refueling outage, whichever sample is larger, if (1) all of the GL 89-10 actions had been satisfactorily completed, (2) no IGSCC had been detected in RWCU piping welds inboard of the second containment isolation valves, and (3) no IGSCC had been detected in RWCU piping welds outboard of the second containment isolation valves after a minimum of 10 percent of the susceptible welds were inspected.

5 ***Monitoring and Trending:*** The extent of and schedule for inspection in accordance with the recommendations of NRC GL 88-01 provide for the timely detection of cracks. Based on inspection results, NRC GL 88-01 provides guidelines for additional samples of welds to be inspected when one or more cracked welds are found in a weld category.

6 ***Acceptance Criteria:*** NRC GL 88-01 recommends that any indication detected be evaluated in accordance with the requirements of ASME Code, Section XI, Subsection IWB-3640.

7 ***Corrective Actions*****:** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

The guidelines in NRC GL 88-01 are followed for replacements, stress improvement, and weld overlay repairs.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** IGSCC has occurred in small- and large-diameter BWR piping made of austenitic SS. The comprehensive program outlined in NRC GL 88-01 and NUREG–0313 addresses improvements in all elements that cause SCC or IGSCC (e.g., susceptible material, significant tensile stress, and an aggressive environment) and is effective in managing IGSCC in austenitic SS piping in the RWCU system.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.55a, "Codes and Standards." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

ASME. ASME Code Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." New York, New York: The American Society of Mechanical Engineers. 2008.[1]

NRC. Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping." Agencywide Documents Access and Management System (ADAMS) Accession No. ML031150675. Washington, DC: U.S. Nuclear Regulatory Commission. January 27, 1988.

_____. Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping." Supplement 1. ADAMS Accession No. ML031130421. Washington, DC: U.S. Nuclear Regulatory Commission. February 4, 1992.

_____. Generic Letter 89-10, "Safety-related Motor Operated Valve Testing and Surveillance." ADAMS Accession No. ML031150307. Washington, DC: U.S. Nuclear Regulatory Commission. August 3, 1990.

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

_____. NUREG–0313, “Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping.” Revision 2. ADAMS Accession No. ML031470422. Washington, DC: U.S. Nuclear Regulatory Commission. January 31, 1988.

_____. Pulsifer, Robert M., U.S. Nuclear Regulatory Commission, letter to Michael A Balduzzi, Vermont Yankee Nuclear Power Corporation, “Review of Request to Discontinue Intergranular Stress Corrosion Cracking Inspection of RWCU Piping Welds Outboard of the Second Containment Isolation Valves (TAC No. MB0468).” ADAMS Accession No. ML010780094. March 27, 2001.

_____. Shea, Joseph W., U.S. Nuclear Regulatory Commission, letter to George A. Hunger, Jr., PECO Energy Company, “Reactor Water Cleanup (RWCU) System Weld Inspections at Peach Bottom Atomic Power Station, Units 2 and 3 (TAC Nos. M92442 and M92443).” ADAMS Accession No. ML090930466. September 15, 1995.

XI.M26 FIRE PROTECTION

Program Description

The Fire Protection aging management program (AMP) includes a fire barrier inspection program. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals; fire barrier walls, ceilings, and floors; fire damper housings; and periodic visual inspection and functional tests of fire-rated doors to provide reasonable assurance that their operability is maintained. The AMP also includes periodic inspection and testing of the halon/carbon dioxide (CO_2) or clean agent fire suppression system. Additionally, this AMP is complemented by Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.S6, “Structures Monitoring” and XI.S5, “Masonry Walls”, which consist of periodic visual inspections by personnel qualified to monitor structures and components (SCs) and masonry walls for applicable aging effects. Therefore, the Structures Monitoring and Fire Protection programs together manage applicable aging effects for structural fire barriers, and the Masonry Walls and Fire Protection programs together manage applicable aging effects for masonry walls that are considered fire barriers.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 50.48(a), each operating nuclear power plant licensee must have a fire protection plan that satisfies General Design Criteria 3, “Fire Protection,” of Appendix A, “General Design Criteria for Nuclear Power Plants,” to 10 CFR Part 50, “Domestic Licensing of Production and Utilization Facilities.”

Licensees of plants that were licensed to operate before January 1, 1979, must meet the requirements of Appendix R, “Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979,” to 10 CFR Part 50, except to the extent provided for in 10 CFR 50.48(b)(TN249). Licensees of plants licensed to operate after January 1, 1979, must meet the plant-specific fire protection licensing basis. Regulatory Guide (RG) 1.189, “Fire Protection for Nuclear Power Plants,” provides guidance for compliance with 10 CFR 50.48(b) and plant-specific fire protection licensing basis.

As an alternative to 10 CFR 50.48(b) or to the plant-specific fire protection licensing basis, licensees may also adopt and maintain a fire protection program that meets 10 CFR 50.48(c), “National Fire Protection Association Standard NFPA 805,” or that incorporates by reference National Fire Protection Association (NFPA) 805, “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition,” with certain exceptions. RG 1.205, “Risk-Informed, Performance-Based Fire Protection for Existing Light-Water Nuclear Power Plants,” provides guidance for compliance with 10 CFR 50.48(c).

The deterministic means for meeting these requirements come from 10 CFR Part 50, Appendix R, and 10 CFR 50.48 or from plant-specific requirements incorporated in the operating license of plants licensed after that date. The U.S. Nuclear Regulatory Commission (NRC) deterministic fire protection requirements are documented in 10 CFR Part 50, Appendix R and 10 CFR 50.48.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages the effects of loss of material and cracking, increased hardness, shrinkage and loss of strength on the intended function of the penetration seals; fire barrier walls, ceilings, and floors; fire damper housings; and other fire resistance materials (e.g., Flamemastic, 3M fire wrapping (including materials used to secure fire wraps [EPRI 3002013084]), spray-on fire proofing material, intumescent coating, etc.) that serve a fire barrier function; and all fire-rated doors (automatic or manual) that perform a fire barrier function. It also manages the aging effects on the intended function of the halon/CO_2 or clean agent fire suppression system.

2 ***Preventive Actions:*** This is a condition monitoring program. However, the fire hazard analysis assesses the fire potential and fire hazard in all plant areas. It also specifies measures for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability for each fire area containing structures, systems, and components important to safety.

3 ***Parameters Monitored or Inspected:*** Visual inspection of penetration seals examines the surface condition of the seals for any sign of degradation. Visual inspection of the surface condition of the fire barrier walls, ceilings, and floors and other fire barrier materials detects any sign of degradation including structural steel fire proofing. Fire damper housings are inspected for signs of corrosion and cracking. Fire-rated doors are visually inspected to detect any degradation of door surfaces.

The periodic visual inspections of the surface condition for the halon/CO_2 or clean agent fire suppression system are performed.

4 ***Detection of Aging Effects:*** Visual inspection of penetration seals detects cracking, seal separation from walls, ceilings, floors, and components, and rupture and puncture of seals. Visual inspection by fire protection qualified personnel of not less than 10 percent of each type of seal in walkdowns is performed at a frequency in accordance with an NRC-approved fire protection program (e.g., Technical Requirements Manual, Appendix R program) or at least once during every refueling outage. Visual inspections to detect cracking and loss of material are conducted by fire protection qualified personnel of the fire barrier walls, ceilings, floors, and doors (e.g., wear, missing parts); fire damper housings; and other fire barrier materials including structural steel fire proofing during walkdowns at a frequency in accordance with an NRC-approved fire protection program. Periodic functional tests are conducted on fire doors.

Visual inspections of the halon/CO_2 or clean agent fire suppression system are performed to detect any sign of corrosion before the loss of the component intended function. Periodic testing of the halon/CO_2 or clean agent fire suppression systems is conducted on a schedule in accordance with an NRC-approved fire protection program.

5 ***Monitoring and Trending:*** The results of inspections of the aging effects on fire barrier penetration seals, fire barrier walls, ceilings, and floors and on other fire barrier materials, fire damper housings, and fire doors are trended to provide for timely detection of aging effects so that the appropriate corrective actions can be taken. Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. The performance of the halon/CO_2 fire suppression system is monitored during the periodic test to detect any degradation in the system. These periodic tests provide data necessary for trending.

6 ***Acceptance Criteria:*** Inspection results are acceptable if there are no signs of degradation that could result in the loss of the fire protection capability due to loss of material. The acceptance criteria include (1) no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls, ceilings, floors, and components, separation of layers of material, or ruptures or punctures of seals; (2) no significant indications of cracking and loss of material of fire barrier walls, ceilings, and floors and in other fire barrier materials; (3) no visual indications of missing parts, holes, and wear; (4) no visual indications of cracks or corrosion of fire damper housings; and (5) no deficiencies in the functional tests of fire doors. Also, inspection results for the halon/CO_2 or clean agent fire suppression system are acceptable if there are no indications of excessive loss of material.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

For fire protection SCs identified that are subject to an aging management review for license renewal, the applicant's 10 CFR Part 50, Appendix B, program is used for corrective actions, the confirmation process, and administrative controls for aging management during the subsequent period of extended operation.

During the inspection of penetration seals, if any sign of degradation is detected within that sample, the scope of the inspection is expanded to include additional seals in accordance with the plant's approved fire protection program. If any projected inspection results will not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's corrective action program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Silicone foam fire barrier penetration seals have experienced splits, shrinkage, voids, lack of fill, and other failure modes (NRC Information Notice [IN] 88-56, IN 94-28, and IN 97-70). Degradation of electrical raceway fire barrier such as small holes, cracking, and unfilled seals are found on routine walkdowns (NRC IN 91-47 and NRC Generic Letter 92-08). Fire doors have experienced wear of the hinges and handles.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR Part 50, Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

10 CFR 50.48, "Fire protection." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

NFPA. NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition." Quincy, Massachusetts: National Fire Protection Association. 2001.

_____. EPRI. EPRI 3002013084, "Long-Term Operations: Subsequent License Renewal Aging Affects for Structures and Structural Components (Structural Tools)." Palo Alto, California: Electric Power Research Institute. November 2018.

NRC. Generic Letter 92-08, "Thermo-Lag 330-1 Fire Barrier." ML031130425. Washington, DC: U.S. Nuclear Regulatory Commission. December 17, 1992.

_____. Information Notice 89-52, "Potential Fire Damper Operational Problems." ML031180663. Washington, DC: U.S. Nuclear Regulatory Commission. June 1989.

_____. Information Notice 88-56, "Potential Problems with Silicone Foam Fire Barrier Penetration Seals." ML031150042. Washington, DC: U.S. Nuclear Regulatory Commission. August 4, 1988.

_____. Information Notice 91-47, "Failure of Thermo-Lag Fire Barrier Material to Pass Fire Endurance Test." ML031190452. Washington, DC: U.S. Nuclear Regulatory Commission. August 6, 1991.

_____. Information Notice 94-28, "Potential Problems with Fire-Barrier Penetration Seals." ML031060475. Washington, DC: U.S. Nuclear Regulatory Commission. April 5, 1994.

_____. Information Notice 97-70, "Potential Problems with Fire Barrier Penetration Seals." ML031050108. Washington, DC: U.S. Nuclear Regulatory Commission. September 19, 1997.

_____. Regulatory Guide 1.189, "Fire Protection for Nuclear Power Plants." Revision 4. ML21048A441. Washington, DC: U.S. Nuclear Regulatory Commission. May 2021.

_____. Regulatory Guide 1.205, "Risk-Informed, Performance-Based Fire Protection for Existing Light-Water Nuclear Power Plants." Revision 2. ML21048A448. Washington, DC: U.S. Nuclear Regulatory Commission. May 2021.

XI.M27 FIRE WATER SYSTEM

Program Description

This aging management program (AMP) applies to water-based fire protection system components, including sprinklers; nozzles; fittings; valve bodies; fire pump casings; hydrants; hose stations; standpipes; water storage tanks; and aboveground, buried, and underground piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) codes and standards. Full-flow testing and visual inspections are conducted to ensure that loss of material, cracking, and flow blockage are adequately managed. In addition to NFPA codes and standards, portions of the water-based fire protection system (1) that are normally dry but periodically are subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (2) that cannot be drained or allow water to collect, are subjected to augmented testing or inspections. Also, portions of the system (e.g., fire service main, standpipe) are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions are initiated.

Either dry sprinklers, fast response sprinklers, and sprinklers are replaced before reaching 10 years, 20 years, and 50 years in service, respectively, or a representative sample of dry sprinklers, fast response sprinklers, and sprinklers from one or more sample areas is tested by using the guidance of NFPA 25, "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems." Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M43, "High Density Polyethylene (HDPE) and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping," is used to monitor the external surfaces of buried and underground water-based fire protection system piping and tanks.

Evaluation and Technical Basis

1 ***Scope of Program:*** Components within the scope of water-based fire protection systems include items such as sprinklers, nozzles, fittings, valve bodies, fire pump casings, hydrants, hose stations, fire water storage tanks, fire service mains, and standpipes. The internal surfaces of water-based fire protection system piping that is normally drained, such as dry-pipe sprinkler system piping, are included within the scope of the AMP. Fire hose stations and standpipes are considered piping in the AMP. Fire hoses and gaskets can be excluded from the scope of license renewal if the standards that are relied upon to prescribe replacement of the hose and gaskets are identified in the scoping methodology description.

2 ***Preventive Actions:*** Flushes (e.g., NFPA 25, Section 7.3.2.1) mitigate or prevent fouling, which can cause flow blockage or loss of material, by clearing corrosion products and sediment.

3 ***Parameters Monitored or Inspected:*** Loss of material and cracking could result in system failure. Flow blockage due to fouling from the buildup of corrosion products or sediment in the system could occur. Therefore, the parameters monitored are the system's ability to maintain required pressure, flow rates, and the system's internal conditions. Periodic flow tests, flushes, internal and external visual inspections, and testing of sprinklers are performed. When visual inspections are used to detect loss of material, the inspection technique is capable of detecting surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric wall thickness examinations are performed. Volumetric wall thickness inspections are conducted on portions of water-based fire

protection system components that are periodically subjected to flow but are normally dry. Visual examinations of cementitious materials are conducted to detect indications of loss of material and cracking that could affect the system's ability to maintain pressure.

4 ***Detection of Aging Effects:*** Water-based fire protection system components are subject to flow testing (except for fire water storage tanks), other testing, and visual inspections. Testing and visual inspections are performed in accordance with Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations." Unless recommended otherwise, external visual inspections are conducted on a refueling outage interval.

a. Flow tests confirm the system is functional by verifying the capability of the system to deliver water to fire suppression systems at required pressures and flow rates.

b. Visual inspections are capable of evaluating (1) the condition of the external surfaces of components, (2) the conditions of the internal surfaces of components that could indicate wall loss or cracking, and (3) the inner diameter of the piping as it applies to the design flow of the fire protection system (i.e., to verify that corrosion product buildup has not resulted in flow blockage due to fouling). Internal visual inspections used to detect loss of material should be capable of detecting surface irregularities that could be indicative of an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric examinations are performed.

c. Visual inspection of yard fire hydrants and fire hydrant flow tests are conducted to provide opportunities to detect degradation before a loss of intended function can occur.

Portions of water-based fire protection system components that have been wetted but are normally dry, such as dry-pipe or preaction sprinkler system piping and valves, are subjected to augmented testing and inspections beyond those of Table XI.M27-1. The augmented tests and inspections are conducted on piping segments that cannot be drained or piping segments that allow water to collect, as follows:

- In each 5-year interval, beginning 5 years prior to the subsequent period of extended operation, either conduct a flow test or flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect.
- In each 5-year interval of the subsequent period of extended operation, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, microbiologically influenced corrosion [MIC]). The 20 percent of piping that is inspected in each 5-year interval is in different locations than previously inspected piping.
- If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary.

For portions of the normally dry piping that are configured to drain (e.g., pipe slopes toward a drain point) the tests and inspections of Table XI.M27-1 do not need to be augmented.

The inspections and tests of all water-based fire protection components occur at the intervals specified in Table XI.M27-1. Fire water storage tank bottom surfaces exposed to soil or concrete are inspected in accordance with GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," Table . For indoor fire water storage tanks exposed to concrete, this only applies if the tank bottom-to-concrete interface surface is periodically exposed to moisture.

If the environment (e.g., type of water, flowrate, temperature) and material that exist on the interior surface of the underground and buried fire protection piping are similar to the conditions that exist within the above-grade fire protection piping, the results of the inspections of the above-grade fire protection piping can be extrapolated to evaluate the condition of buried and underground fire protection piping for the purpose of identifying inside diameter loss of material.

The water-based fire protection systems are normally maintained at required operating pressure and monitored in such a way that loss of system pressure is immediately detected and corrected when acceptance criteria are exceeded. Continuous system pressure monitoring or equivalent methods (e.g., number of jockey fire pump starts or run time) are conducted.

Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. The inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes.

Aging effects associated with fire water system components having only current licensing basis intended functions of leakage boundary (spatial) or structural integrity (attached) as defined in the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR) Table 2.1-4(b) may be managed by the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," and GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." Flow blockage due to fouling need not be managed for these components.

Table XI.M27-1. Fire Water System Inspection and Testing Recommendations[a, b, c]

Description	Periodicity
Sprinkler Systems	
Sprinkler inspections[b]	Annual[d]
Sprinkler testing[e]	After dry sprinklers, fast response sprinklers, and sprinklers having been in service for 10, 20, and 50 years, respectively, and then on a 10-year periodicity
Standpipe and Hose Systems	
Flow tests	Five years[f]
Private Fire Service Mains	
Mainline Strainer	Annual and after each significant flow[g]
Underground and exposed piping flow tests	Five years
Hydrants	Annual [d, h]
Fire Pumps	
Suction screens and strainers	Annual and after each system actuation[d, i]
Water Storage Tanks	
Exterior inspections	Refueling outage interval[j]
Interior inspections	Three years when tank is not internally coated, otherwise 5 years[k]
Valves and System-Wide Testing	
Main drain test	Annual[d, l, n]
Water Spray Fixed Systems	
Strainers	After each system actuation[d]
Operation test	Refueling outage interval[n]
Foam Water Sprinkler Systems	
Strainers	After each system actuation
Operational Test Discharge Patterns	Annually[d]
Internal visual inspection for internal corrosion	10 years
Obstruction Investigation	
Internal inspection of piping[o]	Five years
Obstruction Investigation and Prevention	When the conditions cited in NFPA 25 Sections 14.3.1 (2), (3), (4), (5), (6), (13), or (14) occur

(a) All test and inspection terms are referenced to NFPA 25. The staff cites NFPA 25 for the description of the scope of specific inspections and tests. This table specifies the inspections and tests that are related to managing applicable aging effects associated with loss of material and flow blockage for passive long-lived in-scope components in the fire water system. For example, inspecting a fire hydrant barrel to determine whether it has drained after testing is conducted provides indication of whether the drain field is potentially experiencing flow blockage due to sediment accumulation. Inspections and tests not related to the above continue to be conducted in accordance with the plant's current licensing basis (CLB). If the CLB specifies more frequent inspections than those cited in this table, the plant's CLB continues to be met.

(b) Items in areas that are inaccessible because of safety considerations, such as those raised by continuous process operations, radiological dose, or energized electrical equipment, are inspected during each scheduled shutdown but not more often than once during every refueling outage interval.

(c) Calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.

(d) Where NFPA 25 or this table cite annual testing or inspections, testing and inspections can be conducted on a refueling outage interval if plant-specific operating experience has shown no loss of intended function of the in-scope SSC due to aging effects being managed for the specific component (e.g., loss of material, flow blockage due to fouling).

(e) For wet pipe sprinkler systems, the subsequent license renewal application either:

- provides a plant-specific evaluation demonstrating that the water is not corrosive to the sprinklers (e.g., corrosion-resistant sprinklers); or
- proposes a one-time test of sprinklers that have been exposed to water; the application includes the sample size, sample selection criteria, and minimum time in service of tested sprinklers; or
- proposes to test the sprinklers in accordance with NFPA 25 Section 5.3.1.1.2.

(f) When all the flow tests at the most hydraulically remote hose connections of each zone conducted no earlier than 5 years prior to the subsequent period of extended operation meet the design pressure at the required flow acceptance criteria, subsequent tests may be conducted on a representative sample of 20 percent of the population (defined as components having the same material and environment combination) or a maximum of 25 per population at each unit.

(g) See NFPA 25 Sections 7.2.2.3 and A.7.2.2.3 for additional information about mainline strainer inspections.

(h) In lieu of meeting NFPA 25 Section 7.3.2.4, “[f]ull drainage shall take no longer than 60 minutes,” it is acceptable to observe that the hydrant barrel has drained down to at least 6 inches below the frost line as long as there is no plant-specific operating experience related to freezing of hydrant water at or below this water level.

(i) Suction screen and strainer inspections can be conducted every 5 years in lieu of annually and after each system actuation when (1) the fire water pump does not take suction directly from a source of makeup with the potential for bulk debris (e.g., cooling tower basin, intake structure with potential bulk debris); and (2) screen inspections have met acceptance criteria starting no earlier than 5 years prior to the subsequent period of extended operation. Depending on the installation, there may also be an intake strainer, like that shown in NFPA 25 Figure A.8.2.2.

(j) For insulated fire water storage tanks, inspection of the exterior surfaces of the tank can be conducted consistent with the insulation removal and inspection recommendations in AMP XI.M29 in lieu of annual inspections.

(k) Regarding the additional examinations when steel tanks exhibit signs of interior pitting, corrosion, or failure of coating: When degraded coatings are detected, the acceptance criteria and corrective action recommendations in GALL-SLR Report AMP XI.M42 are followed in lieu of NFPA 25 Section 9.2.7 (1), (2), and (4). When interior pitting or general corrosion (beyond minor surface rust) is detected, tank wall thickness measurements are conducted as stated in NFPA 25 Section 9.2.7 (3) in the vicinity of the loss of material. Vacuum box testing as stated in NFPA 25 Section 9.2.7 (6) is conducted when pitting, cracks, or loss of material are detected in the immediate vicinity of welds.

(l) For main drain tests:

- When main drain tests have met acceptance criteria and plant-specific operating experience has not revealed any flow blockage in fire water system piping in the pipe size for the main drains or larger, a representative sample of 20 percent of the main drain test population (defined as components having the same material and environment combination) or a maximum of 25 per population are conducted at each unit.
- When all the main drain tests conducted no earlier than 5 years prior to the subsequent period of extended operation meet the acceptance criteria and no adverse trend is evident, subsequent inspections can be conducted at a 5-year interval versus annual testing.

(m) For main drain test:

- Consistent with NFPA 25 Section 13.2.5.2, when there is a 10 percent reduction in full flow pressure when test results are compared, the cause of the reduction is identified and corrected, if necessary. To identify whether significant degradation of the fire water system supply has been occurring over several years, test-to-test pressure monitoring full flow pressures should not be compared only to the immediately prior test result.

(n) If past testing results demonstrate that potential nozzle plugging does not impede discharge patterns or prevent the discharge pattern from reaching wetted surfaces to be protected, the test frequency does not exceed 3 years. Otherwise, tests are conducted annually except for protected components that are inaccessible because of safety considerations such as those raised by continuous process operations, radiological dose, or energized electrical equipment are tested during each scheduled shutdown, but not more often than every refueling outage interval.

(o) The alternative nondestructive examination methods permitted by NFPA 25 Sections 14.2.1.1 and 14.3.2.3 are limited to those that can ensure that flow blockage will not occur.

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5 ***Monitoring and Trending:*** Visual inspection results are monitored and evaluated. System discharge pressure or equivalent methods (e.g., number of jockey fire pump starts or run time) are monitored continuously and evaluated. Results of flow testing (e.g., buried and underground piping, fire mains, and sprinkler), flushes, and wall thickness measurements are monitored and trended. Degradation identified by flow testing, flushes, and inspections is evaluated.

Where practical, degradation identified is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

6 ***Acceptance Criteria:*** The acceptance criteria are (1) the water-based fire protection system is able to maintain required pressure and flow rates, (2) minimum design wall thickness is maintained, and (3) no loose fouling products exist in systems that could cause flow blockage in the sprinklers or deluge nozzles.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

If the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material is removed and the inspection results are entered into the site's corrective action program for further evaluation.

If a flow test or a main drain test does not meet the acceptance criteria due to current or projected degradation (i.e., trending) additional tests are conducted. The increased number of tests is determined in accordance with the site's corrective action process; however, there are no fewer than two additional tests for each test that did not meet the acceptance criteria. The additional inspections are completed within the interval (i.e., 5 years, annual) in which the original test was conducted. If subsequent tests do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. At multi-unit sites, the additional tests include at least one test at the other unit on the site, or one of the units at a three-unit site with the same material, environment, and aging effect combination.

An evaluation is conducted to determine whether deposits need to be removed to determine whether loss of material has occurred. When loose fouling products that could cause flow blockage in the sprinklers are detected, a flush is conducted in accordance with the guidance in NFPA 25 Appendix D.5, "Flushing Procedures." If any projected inspection results will not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's corrective action program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Operating experience (OE) shows that water-based fire protection systems are subject to loss of material due to corrosion, MIC, or fouling; and flow blockages due to fouling. Loss of material has resulted in sprinkler system flow blockages, failed flow tests, and piping leaks. Inspections and testing performed in accordance with NFPA standards coupled with visual inspections are capable of detecting degradation prior to loss of intended function. The following OE may be of significance to an applicant's program:

a. In October 2004, a fire main failed its periodic flow test due to a low cleanliness factor. The low cleanliness factor was attributed to fouling because of an accumulation of corrosion products on the interior of the pipe wall and tuberculation. Subsequent chemical cleaning to remove the corrosion products from the pipe wall revealed several leaks. Corrosion products removed during the chemical cleaning were observed to settle out in normally stagnant sections of the water-based fire protection system, resulting in flow blockages in small diameter piping and valve leak-by. (Discussions as part of Requests for Additional Information are available at Agencywide Documents Access and Management System [ADAMS] Accession Nos. ML12220A162, ML12306A332, and ML13029A244).

b. In October 2010, a portion of a preaction spray system failed its functional flow test because of flow blockages. Two branch lines were found to have significant blockages. The blockage in one branch line was determined to be a buildup of corrosion products. A rag was found in the other branch line. (ADAMS Accession No. ML13014A100).

c. In August 2011, an intake fire protection preaction sprinkler system was unable to pass flow during functional testing. Subsequent visual inspections identified flow blockages in the inspector's test valve, the piping leading to the inspector's test valves, and three vertical risers. The flow blockages were determined to be a buildup of corrosion products (ADAMS Accession No. ML113050425).

d. In March 2012, the staff and licensee personnel found that a portion of the internally galvanized piping of a 6-inch preaction sprinkler system could not be properly drained because the drainage points were located on a smaller diameter pipe that tied into the side of the 6-inch pipe. A boroscopic inspection of the lower portions of the pipe showed that it contained residual water, that the galvanizing had been removed, and that significant quantities of corrosion products were present, whereas in the upper dry portions, the galvanized coating was still intact (Information Notice 2013-06).

The review of plant-specific OE during the development of this program is to be broad and detailed enough to detect instances of aging effects that have occurred repeatedly. In some instances, repeatedly occurring aging effects (e.g., recurring internal corrosion) might result in augmented aging management activities. Further evaluation aging management review line items in SRP-SLR Sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6, “Loss of Material due to Recurring Internal Corrosion,” include criteria for determining whether recurring internal corrosion is occurring and recommendations related to augmenting aging management activities.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016.

NFPA. NFPA 25, “Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems, 2011 Edition.” Quincy, Massachusetts: National Fire Protection Association. 2011.

NRC. Information Notice 2013-06, “Corrosion in Fire Protection Piping Due to Air and Water Interaction.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML13031A618. Washington, DC: U.S. Nuclear Regulatory Commission. March 25, 2013.

XI.M29 OUTDOOR AND LARGE ATMOSPHERIC METALLIC STORAGE TANKS

Program Description

The Outdoor and Large Atmospheric Metallic Storage Tanks aging management program (AMP) manages the effects of loss of material and cracking on the outside and inside surfaces of metallic aboveground tanks constructed on concrete or soil. All metallic outdoor tanks (except fire water storage tank interior surfaces and exterior surfaces not exposed to soil or concrete) and certain indoor metallic tanks are included. If the tank exterior is fully accessible, tank outside surfaces may be inspected under the program for inspection of external surfaces (Generic Aging Lessons Learned for Subsequent License Renewal [GALL-SLR] Report AMP XI.M36) for visual inspections of external surfaces recommended in this AMP; surface examinations are conducted in accordance with the recommendations of this AMP. This program credits the standard industry practice of coating or painting the external surfaces of steel tanks as being a preventive measure to mitigate corrosion. The program relies on periodic inspections to monitor the degradation of the protective paint or coating. Tank inside surfaces are inspected by visual or surface examinations as required to detect applicable aging effects.

For storage tanks supported on earthen or concrete foundations, thickness measurements of the tank bottom are conducted because corrosion could occur at inaccessible locations.

Evaluation and Technical Basis

1 ***Scope of Program:*** Tanks within the scope of this program include (1) all metallic outdoor tanks (except fire water storage tank interior surfaces and exterior surfaces not exposed to soil or concrete) constructed on soil or concrete; (2) indoor large-volume metallic storage tanks (i.e., those with a capacity greater than 100,000 gallons) designed to internal pressures approximating atmospheric pressure and exposed internally to water; and (3) other indoor metallic tanks that sit on, or are embedded in, concrete where plant-specific operating experience reveals that the tank bottom (or sides for embedded tanks) to concrete interface is periodically exposed to moisture. If the tank exterior is fully accessible, tank outside surfaces may be inspected under the program for inspection of external surfaces (GALL-SLR Report AMP XI.M36). Aging effects for fire water storage tank interior surfaces and exterior surfaces not exposed to soil or concrete are managed using GALL-SLR Report AMP XI.M27. Visual inspections are conducted on tank insulation and jacketing when they are installed.

This program may be used to manage the aging effects of coatings/linings that are applied to the internal surfaces of components included in the scope of this program as long as the following are met:

- The recommendations of GALL-SLR Report AMP XI.M42 are incorporated into this AMP.
- Exceptions or enhancements associated with the recommendations in GALL-SLR Report AMP XI.M42 are included in this AMP.
- The Final Safety Analysis Report (FSAR) supplement for GALL-SLR Report AMP XI.M42, as shown in Table XI-01, “FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs,” is included in the application with a reference to this AMP.

2 ***Preventive Actions:*** In accordance with industry practice, steel tanks may be coated with protective paint or coating to mitigate corrosion by protecting the external surface of the tank from environmental exposure. For outdoor tanks, sealant or caulking is applied at the interface between the tank external surface and the concrete or earthen surface (e.g., foundation, tank interface joint in a partially encased tank) to mitigate corrosion of the tank by minimizing the amount of water and moisture penetrating the interface. Certain tank configurations may minimize the amount of water and moisture penetrating these interfaces by design, (e.g., the foundation is sloped in a manner that prevents water from accumulating).

3 ***Parameters Monitored or Inspected:*** The program consists of periodic inspections of metallic tanks (with or without coatings) to manage the effects of corrosion and cracking on the intended function of these tanks. Inspections cover all surfaces of the tank (i.e., outside uninsulated surfaces, outside insulated surfaces, bottom, interior surfaces). The AMP uses periodic plant inspections to monitor the degradation of coatings, sealants, and caulking because it is a condition directly related to the potential loss of material or cracking. Thickness measurements of the bottoms of the tanks are conducted periodically. Periodic internal visual inspections and surface examinations, as required to detect applicable aging effects, are performed to detect degradation that could be occurring on the inside of the tank. Where the exterior surface is insulated for outdoor tanks and indoor tanks operated below the dew point, a representative sample of the insulation is periodically removed or inspected to detect the potential for loss of material or cracking underneath the insulation, unless it is demonstrated that the aging effect (i.e., stress corrosion cracking [SCC], loss of material) is not applicable, see Table XI.M29-1, “Tank Inspection Recommendations.”

4 ***Detection of Aging Effects:*** Tank inspections are conducted in accordance with Table XI.M29-1 and the associated table notes. Degradation of an exterior metallic surface can occur in the presence of moisture; therefore, periodic visual inspections during each outage are conducted to confirm that the paint, coating, sealant, and caulking are intact. The visual inspections of sealant and caulking are supplemented by conducting physical manipulation to detect degradation. If the exterior surface is not coated, visual inspections of the tank’s surface are conducted within sufficient proximity (e.g., distance, angle of observation) to detect loss of material. If the tank is insulated, the inspections include locations where potential leakage past the insulation could be accumulating.

When necessary to detect cracking in materials susceptible to cracking such as stainless steel and aluminum, the program includes surface examinations. When surface examinations are required to detect an aging effect, the program states how many surface examinations will be conducted, the area covered by each examination, and how examination sites will be selected.

If the exterior surface of an outdoor tank or indoor tank exposed to condensation (because of the in-scope component being operated below the dew point) is insulated, sufficient insulation is removed to determine the condition of the exterior surface of the tank, unless it is demonstrated that the aging effect (i.e., SCC, loss of material) is not applicable; see Table XI.M29-1, “Tank Inspection Recommendations.” When an aging effect requires management, periodic inspections are conducted. During each 10-year period of the subsequent period of extended operation, remove a minimum of either 25 one-square foot sections or 20 percent of the tank insulation and perform inspection of the exposed exterior surface of the tank. Samples are taken from multiple locations to ensure that a representative sample is examined, focusing on the components most susceptible to the applicable aging effect. Aging effects associated with corrosion under insulation for outdoor tanks may be managed by GALL-SLR Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components.”

The sample inspection points are distributed in such a way that inspections occur on the tank dome (if it is flat), near the bottom, at points where structural supports, pipe, or instrument nozzles penetrate the insulation and where water could collect such as on top of stiffening rings. In addition, inspection locations are based on the likelihood of corrosion under insulation occurring (e.g., given how often a potential inspection location is subject to alternate wetting and drying in environments where trace contaminants could be present, how long a system at a potential inspection location operates below the dew point).

<u>Alternatives to Removing Insulation</u>:

a. Subsequent inspections may consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation when the results of the initial inspection meet the following criteria:

    i. No loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction is observed.

    ii. No evidence of SCC is observed.

b. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or jacketing, or there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), periodic inspections under the insulation continue as conducted for the initial inspection.

c. Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of corrosion under insulation is low for tightly adhering insulation. Tightly adhering insulation is considered to be a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope tanks that have tightly adhering insulation is visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections are not credited toward the inspection quantities for other types of insulation.

The potential loss of material and cracking of tank bottoms is determined by conducting volumetric inspections of the tank bottoms whenever the tank is drained or at intervals not less than those recommended in Table XI.M29-1.

When inspections are conducted on a sampling basis, subsequent inspections are conducted in different locations unless the program states the basis for why repeated inspections will be conducted in the same location.

Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections and tests within the scope of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) follow procedures consistent with the ASME code. Non-ASME Code inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

Table XI.M29-1. Tank Inspection Recommendations[a, b]

Inspections to Identify Degradation of Inside Surfaces of Tank Shell, Roof[c], and Bottom[d, e]				
Material	**Environment**	**Aging Effect Requiring Management (AERM)**	**Inspection Technique[f]**	**Inspection Frequency**
Steel	Air, condensation	Loss of material	Visual from inside surface (IS) or Volumetric from outside surface (OS)[g]	Each 10-year period starting 10 years before the subsequent period of extended operation
	Raw water, waste water	Loss of material		Each 10-year period starting 10 years before the subsequent period of extended operation
	Treated water	Loss of material		One-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32[h]
Stainless steel[h]	Air, condensation	Loss of material	Visual	Each refueling outage interval or one-time inspection; see SRP-SLR Sections 3.2.2.2.2, 3.3.2.2.4, or 3.4.2.2.3.
		Cracking	Surface[i]	Each 10-year period starting 10 years before the subsequent period of extended operation, or one-time inspection; see SRP-SLR Sections 3.2.2.2.4, 3.3.2.2.3, or 3.4.2.2.2.
	Raw water, waste water	Loss of material	Visual	Each 10-year period starting 10 years before the subsequent period of extended operation
	Treated water, treated borated water	Loss of material	Visual from IS or Volumetric from OS[g]	One-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32[h]
Aluminum	Air, condensation	Loss of material	Visual	Each 10-year period starting 10 years before the subsequent period of extended operation, or one-time inspection; see SRP-SLR Sections 3.2.2.2.10, 3.3.2.2.10, or 3.4.2.2.9.
		Cracking	Surface[i]	Each 10-year period starting 10 years before the subsequent period of extended operation, or demonstrate that SCC is not an applicable aging effect; see SRP-SLR Sections 3.2.2.2.8, 3.3.2.2.8, or 3.4.2.2.7.
	Treated water, treated borated water	Loss of material	Visual from IS or Volumetric from OS[g]	One-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32[h]

Inspections to Identify Degradation of Inside Surfaces of Tank Shell, Roof[c], and Bottom[d, e]				
Material	**Environment**	**Aging Effect Requiring Management (AERM)**	**Inspection Technique[f]**	**Inspection Frequency**
	Raw water, waste water	Loss of material	Visual	Each 10-year period starting 10 years before the subsequent period of extended operation, or one-time inspection; see SRP-SLR Sections 3.2.2.2.10, 3.3.2.2.10, or 3.4.2.2.9.
		Cracking	Surface[i]	Each 10-year period starting 10 years before the subsequent period of extended operation, or demonstrate that SCC is not an applicable aging effect; see SRP-SLR Sections 3.2.2.2.8, 3.3.2.2.8, or 3.4.2.2.7.
Inspections to Identify Degradation of External Surfaces[j] of Tank Shell, Roof, and Bottom				
Material	Environment	AERM	Inspection Technique[f]	Inspection Frequency
Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Visual from OS	Each refueling outage interval
	Soil, concrete	Loss of material	Volumetric from IS[j]	Each 10-year period starting 10 years before the subsequent period of extended operation[k]
Stainless Steel	Air, condensation	Loss of material	Visual from OS	Each refueling outage interval or one-time inspection; see SRP-SLR Sections 3.2.2.2.2, 3.3.2.2.4, or 3.4.2.2.3.
		Cracking	Surface[i]	Each 10-year period starting 10 years before the subsequent period of extended operation or one-time inspection; see SRP-SLR Sections 3.2.2.2.4, 3.3.2.2.3, or 3.4.2.2.2.
	Soil, concrete	Loss of material	Volumetric from IS[l]	Each 10-year period starting 10 years before the subsequent period of extended operation[m]
		Cracking	Volumetric from IS[l]	Each 10-year period starting 10 years before the subsequent period of extended operation[m]
Aluminum	Air, condensation	Cracking	Surface[i]	Each 10-year period starting 10 years before the subsequent period of extended operation or demonstrate that SCC is not an applicable aging effect; see SRP-SLR Sections 3.2.2.2.8, 3.3.2.2.8, or 3.4.2.2.7.

Inspections to Identify Degradation of Inside Surfaces of Tank Shell, Roof(c), and Bottom(d, e)				
Material	**Environment**	**Aging Effect Requiring Management (AERM)**	**Inspection Technique(f)**	**Inspection Frequency**
		Loss of material	Visual from OS	Each 10-year period starting 10 years before the subsequent period of extended operation, or one-time inspection; see SRP-SLR Sections 3.2.2.2.10, 3.3.2.2.10, or 3.4.2.2.9.
	Soil, concrete	Loss of material	Volumetric from IS(l)	Each 10-year period starting 10 years before the subsequent period of extended operation(m)
		Cracking	Volumetric from IS(l)	Each 10-year period starting 10 years before the subsequent period of extended operation(m) or demonstrate that SCC is not an applicable aging effect; see SRP-SLR Sections 3.2.2.2.8, 3.3.2.2.8, or 3.4.2.2.7.

(a) The Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M30, "Fuel Oil Chemistry," is used to manage loss of material on the internal surfaces of fuel oil storage tanks. However, for outdoor fuel oil storage tanks exposed to soil or concrete and indoor tanks exposed to periodically wetted concrete or exposed to soil, inspections to identify aging of the external surfaces of tanks are conducted in accordance with GALL-SLR Report AMP XI.M29. GALL-SLR Report AMP XI.M41 is used to manage loss of material and cracking for the external surfaces of buried tanks.

(b) When one-time internal inspections in accordance with these footnotes are used in lieu of periodic inspections, the one-time inspection must occur within the 5-year period before the start of the subsequent period of extended operation.

(c) Nonwetted surfaces on the inside of a tank (e.g., roof, surfaces above the normal waterline) are inspected in the same manner as the wetted surfaces based on the material, environment, and AERM.

(d) Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom cover all the inside surfaces. Where this is not possible because of the tank's configuration (e.g., tanks with floating covers or bladders), the subsequent license renewal application includes a justification for how aging effects will be detected before the loss of the tank's intended function.

(e) For tank configurations in which deleterious materials could accumulate on the tank bottom (e.g., sediment, silt), the internal inspections of the tank's bottom include inspections of the side wall of the tank up to the top of the sludge-affected region.

(f) Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g., inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated to be effective at detecting the aging effects requiring management (AERMs) and a sufficient amount of the surface is inspected to provide reasonable assurance that localized aging effects are detected. For example, in some cases, subject to being demonstrated effective by the applicant, the low-frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. If follow-up ultrasonic examinations are conducted in any areas where the wall thickness is below nominal, an LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom.

(g) At least 20 percent of the tank's internal surface is to be inspected using a method capable of precisely determining wall thickness. The inspection method is capable of detecting both general and pitting corrosion and is demonstrated to be effective by the applicant.

(h) At least one tank for each material and environment combination is inspected at each site. The tank inspection can be credited toward the sample population for GALL-SLR Report AMP XI.M32.

(i) A minimum of either 25 sections of the tank's surface (e.g., 1 square foot sections for tank surfaces, 1 linear foot sections of weld length) or 20 percent of the tank's surface is examined. The sample inspection points are distributed in such a way that inspections occur in the areas most susceptible to degradation (e.g., areas in which contaminants could collect, inlet and outlet nozzles, welds).

(j) For insulated tanks, the external inspections of tank surfaces that are insulated are conducted in accordance with the sampling recommendations in this AMP. If the initial inspections meet the criteria described in the preceding “Alternatives to Removing Insulation” portion of this AMP, subsequent inspections may consist of external visual inspections of the jacketing in lieu of surface examinations. Tanks with tightly adhering insulation may use the “Alternatives to Removing Insulation” portion of this AMP for initial and all follow on inspections.(k) When volumetric examinations of the tank bottom cannot be conducted because the tank is coated, an exception is stated, and the accompanying justification for not conducting inspections includes the considerations in footnote l, below, or an alternative examination methodology is proposed.

(l) A one-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32 may be conducted in lieu of periodic inspections if an evaluation conducted before the subsequent period of extended operation and during each 10-year period during the subsequent period of extended operation demonstrates that the soil under the tank is not corrosive. This should be demonstrated using actual soil samples that are analyzed for each individual parameter (e.g., resistivity, pH, redox potential, sulfides, sulfates, moisture) and overall soil corrosivity. The evaluation includes soil sampling from underneath the tank.
Alternatively, a one-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32 may be conducted in lieu of periodic inspections if the bottom of the tank has been cathodically protected in such a way that the availability and effectiveness criteria of GALL SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks,” Table XI.M41-3, “Inspections of Buried Tanks for all Inspection Periods,” have been met beginning 5 years prior to the subsequent period of extended operation, and the criteria continue to be met throughout the subsequent period of extended operation.

5 ***Monitoring and Trending:*** The effects of corrosion of the tank surfaces are detectable by visual and surface (for cracking) examination techniques. Based on operating experience (OE), periodic inspections provide for timely detection of aging effects. Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components’ intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.

6 ***Acceptance Criteria:*** Any degradation of paints or coatings (cracking, flaking, or peeling), or evidence of corrosion is reported and requires further evaluation to determine whether repair or replacement of the paints or coatings should be conducted. Nonpliable, cracked, or missing sealant and caulking is unacceptable. When degraded sealant or caulking is detected, an evaluation is conducted to determine the need to conduct follow-up examination of the tank’s surfaces. Indications of cracking are analyzed in accordance with the applicable design requirements for the tank. Ultrasonic testing (UT) thickness measurements of the tank bottom are evaluated against the design thickness and corrosion allowance.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Flaws in the caulking or sealant are repaired and follow-up examination of the tank’s surfaces is conducted if deemed appropriate.

Additional inspections are conducted if one of the inspections does not meet the acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the site’s corrective action process; however:

- For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected.
- For other sampling-based inspections (e.g., 20 percent, 25 locations), the smaller of five additional inspections or inspection of 20 percent of the inspection population is conducted. If subsequent inspections do not meet the acceptance criteria, an evaluation of the extent of condition and the extent of cause is conducted to determine the further extent of inspection. At multi-unit sites, the additional inspections include inspections at all of the units that have the same material, environment, and aging effect combination.

The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, with the exception of external visual inspections of tanks without insulation, the additional inspections are completed within the interval during which the original inspection was conducted or, if identified in the latter half of the current inspection interval, during the first half of the next inspection interval. These additional inspections conducted in the next inspection interval cannot also be credited toward the number of inspections in the latter interval. External visual inspections when the tank is not insulated are conducted during the original refueling outage interval.

If any projected inspection results will not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site’s corrective action program. However, for one-time inspections that do not meet the acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** A review of OE reveals that there have been instances involving defects variously described as wall thinning, pinhole leaks, cracks, and through-wall flaws in tanks. In addition, internal blistering, delamination of coatings, rust stains, and holidays have been found on the bottom of tanks.

The review of plant-specific OE during the development of this program is to be broad and detailed enough to detect instances of aging effects that have occurred repeatedly. In some instances, repeatedly occurring aging effects (i.e., recurring internal corrosion) might result in augmented aging management activities. Further evaluation aging management review line items in SRP-SLR Sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6, “Loss of Material Due to Recurring Internal Corrosion,” include criteria to determine whether recurring internal corrosion is occurring and recommendations related to augmenting aging management activities.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016.

NRC. Information Notice 2013-18, “Refueling Water Storage Tank Degradation.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML13128A118. Washington, DC: U.S. Nuclear Regulatory Commission. September 13, 2013.

XI.M30 FUEL OIL CHEMISTRY

Program Description

This program includes (1) surveillance and maintenance procedures to mitigate corrosion and (2) measures to verify the effectiveness of the mitigative actions and confirm the insignificance of an aging effect. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the plant's technical specifications (TSs). Guidelines of the American Society for Testing and Materials (ASTM) Standards, such as ASTM D 0975, D 1796, D 2276, D 2709, D 6217, and D 4057, also may be used. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining or cleaning of tanks and by verifying the quality of new oil before its introduction into the storage tanks. However, corrosion may occur at locations in which contaminants may accumulate, such as tank bottoms. Accordingly, the effectiveness of the program is verified to provide reasonable assurance that significant degradation is not occurring and that the component's intended function is maintained during the subsequent period of extended operation. Thickness measurement of the tank bottom is an acceptable verification program.

The fuel oil chemistry program is generally effective in removing impurities from areas that experience flow. The Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report identifies the circumstances in which the fuel oil chemistry program is augmented to manage the effects of aging for subsequent license renewal (SLR). For example, the fuel oil chemistry program may not be effective in stagnant areas. Accordingly, in certain cases, as identified in this GALL-SLR Report, verification of the effectiveness of the fuel oil chemistry program is conducted. As discussed in this GALL-SLR Report for these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system.

Evaluation and Technical Basis

1 ***Scope of Program:*** Components within the scope of the program are the diesel fuel oil storage tanks, piping, and other metal components subject to aging management review that are exposed to an environment of diesel fuel oil.

2 ***Preventive Actions:*** The program reduces the potential for (1) exposure of the component internal surfaces to fuel oil contaminated with water and microbiological organisms, reducing the potential for age-related degradation in other components exposed to diesel fuel oil; and (2) transport of corrosion products, sludge, or particulates to components serviced by the fuel oil storage tanks. Biocides or corrosion inhibitors may be added as a preventive measure. Periodic cleaning of a tank allows for removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. Coatings, if used, prevent or mitigate corrosion by protecting the internal surfaces of components from contact with water and microbiological organisms.

3 ***Parameters Monitored or Inspected:*** The program is focused on managing loss of material due to general, pitting, and crevice corrosion, and microbiologically influenced corrosion (MIC) of component internal surfaces. The aging management program (AMP) monitors 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. Water and microbiological organisms in the fuel oil storage tank increase the potential for corrosion. Sediment and total particulate content may be indicative of water intrusion or corrosion. Periodic visual inspections of tank internal surfaces and thickness measurements of the bottoms of the tanks are conducted as an additional measure to provide reasonable assurance that loss of material is not occurring.

4 ***Detection of Aging Effects:*** Loss of material due to corrosion of the diesel fuel oil tank or other components exposed to diesel fuel oil cannot occur without exposure of the tank's internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Periodic multilevel sampling provides assurance that fuel oil contaminants are below unacceptable levels. If tank design features do not allow for multilevel sampling, a sampling methodology that includes a representative sample from the lowest point in the tank may be used.

At least once during the 10-year period prior to the subsequent period of extended operation, each diesel fuel tank is drained and cleaned, the internal surfaces are visually inspected (if physically possible) and volumetrically inspected if evidence of degradation is observed during visual inspection, or if visual inspection is not possible. During the subsequent period of extended operation, at least once every 10 years, each diesel fuel tank is drained and cleaned, the internal surfaces are 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 are volumetrically inspected. The external surfaces of tank bottoms for outdoor tanks exposed to soil or concrete and indoor tanks exposed to periodically wetted concrete or exposed to soil are volumetrically inspected in accordance with GALL-SLR Report AMP XI.M29, Table XI.M29-1, Footnote 1.

Prior to the subsequent period of extended operation, a one-time inspection (i.e., GALL-SLR Report AMP XI.M32) of selected components exposed to diesel fuel oil is performed to verify the effectiveness of the Fuel Oil Chemistry program. Certain one-time inspections are not conducted subject to the following:

- For components constructed of the same material as the fuel oil storage tank, when the fuel oil storage tank is not coated on its internal surface, one-time inspections are not conducted.
- For components constructed of materials other than the fuel oil storage tank (when the tank is not internally coated), one-time inspections are not conducted when the SLR application states the basis for why water pooling or separation is not possible for a specific material type.

5 ***Monitoring and Trending:*** Water, biological activity, and particulate contamination concentrations are monitored and trended in accordance with the plant's TSs or at least quarterly. Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.

6 ***Acceptance Criteria:*** Acceptance criteria for fuel oil quality parameters are as invoked or referenced in a plant's TSs. Additional acceptance criteria may be implemented using guidance from industry standards and equipment manufacturer or fuel oil supplier recommendations. ASTM D 0975 or other appropriate standards may be used to develop fuel oil quality acceptance criteria. Suspended water concentrations are in accordance with the applicable fuel oil quality specifications. Corrective actions are taken if microbiological activity is detected. Any degradation of the tank internal surfaces is reported and is evaluated using the corrective action program. Thickness measurements of the tank bottom are evaluated against the design thickness and corrosion allowance.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Corrective actions are taken to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance. If accumulated water is found in a fuel oil storage tank, it is immediately removed. In addition, when the presence of biological activity is confirmed, or if there is evidence of MIC, a biocide is added to fuel oil.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The operating experience (OE) at some plants has included identification of water in the fuel, particulate contamination, and biological fouling. In addition, when a diesel fuel oil storage tank at one plant was cleaned and visually inspected, the inside of the tank was found to have unacceptable pitting corrosion ($>$ 50 percent of the wall thickness), which was repaired in accordance with the American Petroleum Institute (API) 653 standard by welding patch plates over the affected area.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

API. 653, “Tank Inspection, Repair, Alteration, and Reconstruction.” Washington, DC: American Petroleum Institute. April 2009.

ASTM. ASTM D 0975-13, “Standard Specification for Diesel Fuel Oils.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 2004.

_____. ASTM D 1796-11, “Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 1997.

_____. ASTM D 2276-00, “Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 2000.

_____. ASTM D 2709-96 (Reapproved 2011), “Standard Test Method for Water and Sediment in Middle Distillate Fuels by Centrifuge.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 1996.

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_____. ASTM D 6217-11, “Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 1998.

NRC. Regulatory Guide 1.137, “Fuel-Oil Systems for Standby Diesel Generators.” Revision 2. Agencywide Documents Access and Management System (ADAMS) Accession No. ML12300A122. Washington, DC: U.S. Nuclear Regulatory Commission, June 2013.

_____. “Safety Evaluation Report Related to the License Renewal of Three Mile Island Nuclear Unit 1, Section 3.0.3.2.12, Fuel Oil Chemistry–Operating Experience.” ADAMS Accession No. ML091660470. Washington, DC: U.S. Nuclear Regulatory Commission. June 30, 2009.

XI.M31 REACTOR VESSEL MATERIAL SURVEILLANCE

Program Description

Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix H, requires implementation of a Reactor Vessel Material Surveillance program when the peak neutron fluence at the end of the design life of the vessel exceeds 10^{17} n/cm^2 (E > 1 MeV). The purpose of the material surveillance program is to monitor the changes in the fracture toughness of the ferritic reactor vessel beltline materials. As described in Regulatory Issue Summary 2014-11, beltline materials are the ferritic reactor vessel materials that have a projected neutron fluence greater than 10^{17} n/cm^2 (E > 1 MeV) at the end of the license period (for example, the subsequent period of extended operation), which are evaluated to identify the extent of neutron radiation embrittlement for the material. The surveillance capsules contain reactor vessel material specimens and are located near the inside vessel wall in the beltline region so that the specimens duplicate, as closely as possible, the neutron spectrum, temperature history, and maximum neutron fluence experienced at the reactor vessel's inner surface. Because of the location of the capsules between the reactor core and the reactor vessel wall, surveillance capsules typically receive neutron fluence exposures that are higher than those received by the inner surface of the reactor vessel. This allows surveillance capsules to be withdrawn and tested prior to the inner surface receiving an equivalent neutron fluence so that the surveillance test results bound the conditions at the end of the subsequent period of extended operation.

The surveillance program must meet the requirements of 10 CFR Part 50, Appendix H. The American Society for Testing Materials (ASTM) standards incorporated by reference in 10 CFR Part 50, Appendix H, include recommended surveillance capsule withdrawal schedules based on plant operation during the original 40-year license term. Therefore, standby capsules or capsules containing reconstituted specimens may need to be incorporated into the Reactor Vessel Material Surveillance program to provide reasonable assurance of appropriate monitoring during the subsequent period of extended operation. Surveillance capsules are designed and located to permit insertion of replacement capsules. If standby capsule(s) will be incorporated into the Reactor Vessel Material Surveillance program for withdrawal and testing to address the subsequent period of extended operation and each capsule has already been withdrawn from the reactor vessel and placed in storage, each surveillance capsule should be reinserted, if necessary, in a location with an appropriate lead factor to ensure that the neutron fluence of the surveillance capsule and the test results will, at a minimum, bound the peak neutron fluence of interest projected to the end of the subsequent period of extended operation.

This program includes withdrawal and testing of at least one surveillance capsule addressing the subsequent period of extended operation, with a neutron fluence of the surveillance capsule being between one and two times the peak neutron fluence of interest projected at the end of the subsequent period of extended operation. The peak reactor vessel neutron fluence of interest at the end of the subsequent period of extended operation should address the time-limited aging analyses (TLAAs) described in the following sections of the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR), as applicable: Sections 4.2.2.1.2 (Upper-Shelf Energy), 4.2.3.1.3 (Pressurized Thermal Shock) and 4.2.3.1.4 (Pressure-Temperature Limits) for pressurized water reactors (PWRs); and Sections 4.2.2.1.2 (Upper-Shelf Energy), 4.2.3.1.4 (Pressure Temperature Limits), 4.2.3.1.5 (Elimination of Boiling Water Reactor Circumferential Weld Inspection) and 4.2.3.1.6 (Boiling Water Reactor Axial Welds) for boiling water reactors (BWRs). If a capsule meeting this neutron fluence criterion has not been tested prior to entering the subsequent period of extended operation, then the program includes the withdrawal and testing (or alternatively the retrieval from storage, reinsertion for additional neutron fluence accumulation, if necessary, and testing) of one capsule addressing the subsequent period of extended operation to meet this criterion. If a surveillance capsule was previously identified for withdrawal and testing to address the initial period of extended operation, it is not acceptable to redirect or postpone the withdrawal and testing of that capsule to achieve a higher neutron fluence that meets the neutron fluence criterion for the subsequent period of extended operation.

Alternatively, an integrated surveillance program (ISP) may be considered for a set of reactors that have similar design and operating features, as described in 10 CFR Part 50, Appendix H, Paragraph III.C. The plant-specific implementation of the ISP is consistent with the latest version of the ISP plan that has been approved by the U.S. Nuclear Regulatory Commission (NRC) for the subsequent period of extended operation.

The objective of this Reactor Vessel Material Surveillance program is to provide sufficient material data and dosimetry to (1) monitor irradiation embrittlement to a neutron fluence level that is greater than the projected peak neutron fluence of interest projected to the end of the subsequent period of extended operation, and (2) provide adequate dosimetry monitoring during the subsequent period of extended operation. If surveillance capsules are not withdrawn during the subsequent period of extended operation, provisions are made to perform dosimetry monitoring. An in-vessel standby capsule, or a standby capsule that has been retrieved from storage and reinserted, when coupled with the use of an NRC-approved methodology for determining neutron fluence consistent with Regulatory Guide (RG) 1.190 (TN8000), “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” provides an acceptable means of dosimetry monitoring.

The program is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in the upper-shelf energy (USE) as a function of neutron fluence and irradiation temperature. The data from this surveillance program are used to monitor neutron irradiation embrittlement of the reactor vessel, and are inputs to the neutron embrittlement TLAAs described in Section 4.2 of the SRP-SLR. The Reactor Vessel Material Surveillance program is also used in conjunction with the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report, AMP X.M2, “Neutron Fluence Monitoring.”

All surveillance capsules, including those previously withdrawn from the reactor vessel, must meet the test procedures and reporting requirements of the applicable ASTM standards referenced in 10 CFR Part 50, Appendix H, to the extent practicable, for the configuration of the specimens in the capsule. Any changes in the surveillance capsule withdrawal schedule, including the incorporation and change in status of standby capsules to capsules scheduled for withdrawal and testing (or alternatively retrieval from storage, reinsertion for additional neutron fluence accumulation, if necessary, and testing) under this program must be approved by the NRC prior to their implementation, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3. Standby capsules placed in storage (e.g., withdrawn from the reactor vessel) are maintained for possible future insertion, and tested specimens are retained in storage for possible reconstitution.

Evaluation and Technical Basis

The Reactor Vessel Material Surveillance program is plant-specific and depends on the composition and availability of the limiting materials, the availability of surveillance capsules, and the projected neutron fluence at the end of the subsequent period of extended operation. In accordance with 10 CFR Part 50, Appendix H, an applicant submits its proposed withdrawal schedule for NRC approval prior to its implementation.

1 ***Scope of Program:*** The program addresses neutron embrittlement of all ferritic reactor vessel beltline materials as defined by 10 CFR Part 50, Appendix G, as the region of the reactor vessel that directly surrounds the effective height of the active core and the adjacent regions of the reactor vessel that are predicted to experience sufficient neutron damage to be considered in the selection of the limiting material with regard to radiation damage. Materials with a projected neutron fluence greater than 10^{17} n/cm^2 (E > 1 MeV) at the end of the license period (for example, the subsequent period of extended operation), are considered to experience sufficient neutron damage to be included in the beltline. Materials monitored within the licensee's existing, materials surveillance program typically continue to serve as the basis for the reactor vessel surveillance aging management program (AMP).

For ISPs, the plant-specific implementation of the ISP in this Reactor Vessel Material Surveillance program is maintained consistent with the latest version of the ISP plan that has been approved by the NRC for the subsequent period of extended operation.

2 ***Preventive Actions:*** This program is a surveillance program; no preventive actions are identified.

3 ***Parameters Monitored or Inspected:*** The program monitors reduction of the fracture toughness of reactor vessel beltline materials due to neutron irradiation embrittlement, through the periodic testing of material specimens at different intervals that have been irradiated in the surveillance capsules that are a part of the program. The program also monitors the long-term operating conditions of the reactor vessel (i.e., vessel beltline operating temperature and neutron fluence, the latter using GALL-SLR AMP X.M2, "Neutron Fluence Monitoring") that could affect neutron irradiation embrittlement of the reactor vessel.

The program uses two parameters to monitor the effects of neutron irradiation: (1) the increase in the Charpy V-notch 30 ft-lb transition temperature, and (2) the drop in the Charpy V-notch USE. The program uses neutron dosimeters to monitor the neutron fluence of the surveillance capsule and to provide information for benchmarking neutron fluence calculations. Low melting point elements or low melting point eutectic alloys may be used as a check on peak specimen irradiation temperature. Results from these temperature monitors are used to ensure that the exposure temperature of the surveillance capsule is consistent with the reactor vessel beltline operating temperature. The Charpy V-notch specimens, neutron dosimeters, and temperature monitors are placed in capsules that are located within the reactor vessel; the capsules are withdrawn periodically to monitor the reduction in fracture toughness due to neutron irradiation.

This program includes withdrawal and testing of at least one capsule addressing the subsequent period of extended operation with a neutron fluence of the capsule between one and two times the peak neutron fluence of interest at the end of the subsequent period of extended operation. The peak reactor vessel neutron fluence of interest at the end of the subsequent period of extended operation should address the TLAAs as described in the following sections of the SRP-SLR, as applicable: Sections 4.2.2.1.2 (Upper-Shelf Energy), 4.2.3.1.3 (Pressurized Thermal Shock) and 4.2.3.1.4 (Pressure-Temperature Limits) for PWRs; and Sections 4.2.2.1.2 (Upper-Shelf Energy), 4.2.3.1.4 (Pressure Temperature Limits), 4.2.3.1.5 (Elimination of Boiling Water Reactor Circumferential Weld Inspection) and 4.2.3.1.6 (Boiling Water Reactor Axial Welds) for BWRs. If a capsule meeting this neutron fluence criterion has not been tested prior to entering the subsequent period of extended operation, then the program includes the withdrawal and testing (or alternatively the retrieval from storage, reinsertion for additional neutron fluence accumulation, if necessary, and testing) of one capsule to address the subsequent period of extended operation to meet this criterion. If a surveillance capsule was previously identified for withdrawal and testing to address the initial period of extended operation, it is not acceptable to redirect or postpone the withdrawal and testing of that capsule to achieve a higher neutron fluence that meets the neutron fluence criterion for the subsequent period of extended operation. Test results are reported consistent with the requirements of 10 CFR Part 50, Appendix H. Because the degree of neutron irradiation embrittlement is a function of the neutron fluence, calculations of the capsule neutron fluence, the reactor vessel wall neutron fluence, and the peak neutron fluence of interest projected to the end of the subsequent period of extended operation are important parts of the program. The methods used to determine both capsule and reactor vessel wall neutron fluence values are consistent with RG 1.190, as described in GALL-SLR AMP X.M2, “Neutron Fluence Monitoring.”

This program uses separate dosimeter capsules or ex-vessel dosimeters to monitor neutron fluence independent of the specimen capsules if there are no surveillance capsules installed in the reactor vessel.

4 ***Detection of Aging Effects:*** Reactor vessel materials are monitored by a surveillance program in which surveillance capsules are withdrawn from the reactor vessel and tested consistent with 10 CFR Part 50, Appendix H. The ASTM standards referenced in Appendix H describe the methods used to monitor irradiation embrittlement (as described under program element 3, above), selection of materials, and the withdrawal schedule for surveillance capsules. Because the withdrawal schedule in Table 1 of ASTM E185-82 is based on plant operation during the original 40-year license term, standby capsules may need to be incorporated into the program as capsules to be tested within a withdrawal schedule that covers the subsequent period of extended operation. Alternatively, this program can propose implementation of in-vessel irradiation of capsule(s) with reconstituted specimens from previously tested capsules and appropriate neutron fluence monitoring.

Alternatively, an ISP for the subsequent period of extended operation may be considered for a set of reactors that have similar design and operating features, as described in 10 CFR Part 50, Appendix H, Paragraph III.C. For an ISP, in some cases the plant Reactor Vessel Material Surveillance program may result in no surveillance capsules being irradiated in the plant’s reactor vessel, and the plant relying on data derived from testing of the ISP capsules provided by the host plants of the capsules. Additional surveillance capsules may also be needed for the subsequent period of extended operation for an ISP. For ISPs, the plant-specific implementation of the ISP in the Reactor Vessel Material Surveillance program is maintained consistent with the latest version of the ISP plan approved by the NRC for the subsequent period of extended operation. The plant implements dosimetry monitoring as required by the approved ISP to meet the provision of 10 CFR Part 50, Appendix H, Paragraph III.C.1.b, that each reactor in an ISP has an adequate dosimetry program.

If no in-vessel surveillance capsules are available, an alternative neutron fluence monitoring program uses alternative dosimetry, either from in-vessel capsules or ex-vessel capsules, to monitor neutron fluence during the subsequent period of extended operation. The methods used in this alternative neutron fluence monitoring program are consistent with RG 1.190, including appropriate benchmarking, as described in GALL-SLR Report AMP X.M2, “Neutron Fluence Monitoring.”

If not previously approved, the capsule withdrawal schedule for the Reactor Vessel Material Surveillance program shall be submitted as part of the subsequent license renewal application.

If the reactor vessel exposure conditions (neutron flux, spectrum, irradiation temperature, etc.) are altered, then the basis for the projection of neutron fluence to the end of the subsequent period of extended operation is reviewed and appropriate modifications are made to the Reactor Vessel Material Surveillance program. Any changes to the Reactor Vessel Material Surveillance program must be submitted for NRC review and approval in accordance with 10 CFR Part 50, Appendix H, prior to their implementation.

5 ***Monitoring and Trending:*** The program provides data about neutron embrittlement of the reactor vessel materials and neutron fluence data. These data are used to evaluate the TLAAs of neutron irradiation embrittlement (e.g., USE, pressurized thermal shock [PTS], pressure-temperature limits evaluations, etc.) as needed, to demonstrate compliance with the requirements of 10 CFR Part 50 (TN249), Appendix G, and 10 CFR 50.61 or 10 CFR 50.61a for the subsequent period of extended operation, as described in SRP-SLR, Section 4.2.

The plant-specific surveillance program or ISP has at least one capsule that has attained or will attain neutron fluence between one and two times the peak reactor vessel wall neutron fluence of interest at the end of the subsequent period of extended operation. If a capsule meeting this neutron fluence criterion has not been tested previously, then the program includes withdrawal and testing (or alternatively the retrieval from storage, reinsertion for additional neutron fluence accumulation, if necessary, and testing) of one capsule addressing the subsequent period of extended operation. (If a surveillance capsule was previously identified for withdrawal and testing to address the initial period of extended operation, it is not acceptable to redirect or postpone the withdrawal and testing of that capsule to achieve a higher neutron fluence that meets the neutron fluence criterion for the subsequent period of extended operation.) The program withdraws, and subsequently tests, the capsule(s) during an outage during which the capsule receives a neutron fluence of between one and two times the peak reactor vessel neutron fluence of interest at the end of the subsequent period of extended operation. Test results from this capsule are reported as described in 10 CFR Part 50, Appendix H. If an existing standby capsule that has been previously withdrawn from the reactor vessel is used for testing to meet the neutron fluence criterion for the subsequent period of extended operation and the capsule does not require additional irradiation, then that (formerly standby) capsule is incorporated into the surveillance capsule withdrawal schedule of the Reactor Vessel Material Surveillance program upon receipt of the subsequently renewed license, and reporting of the test results is consistent with 10 CFR Part 50, Appendix H, with the “withdrawal date” of the capsule considered to be no later than the date of the subsequently renewed license. If a plant has ample capsules remaining for future use, all pulled and tested samples placed in storage with a reactor vessel neutron fluence less than 37.5 percent of the projected neutron fluence at the end of the subsequent period of extended operation may be discarded. All pulled and tested samples with a neutron fluence greater than 37.5 percent of the projected reactor vessel neutron fluence at the end of the subsequent period of extended operation and all untested capsules are placed in storage (these specimens and capsules are saved for possible future reconstitution and reinsertion use), unless the applicant has gained NRC approval to discard the pulled and tested samples or capsules.

If an applicant does not have an ample number of capsules remaining for future use, all withdrawn and tested capsule specimens are placed in storage. These specimens are saved for future reconstitution, in case irradiation embrittlement monitoring by the surveillance program is reestablished. Tested surveillance specimens may be withdrawn from storage and used in research activities (e.g., microstructural examination, mechanical testing, and/or additional irradiation) without NRC approval if the licensee determines that a sufficient number of specimens will remain.

6 ***Acceptance Criteria:*** Although there are no specific acceptance criteria that apply to the surveillance data themselves, the program meets the requirements of 10 CFR Part 50 (TN249), Appendix H. The reactor vessel embrittlement projections are used to demonstrate compliance with the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.61 or 10 CFR 50.61a, and the acceptability of other plant-specific analyses, throughout the subsequent period of extended operation, as described in the SRP-SLR, Section 4.2.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Because the data from this program are used for reactor vessel embrittlement projections to comply with regulations (e.g., 10 CFR Part 50, Appendix G, requirements, and 10 CFR 50.61 or 10 CFR 50.61a limits) through the subsequent period of extended operation, corrective actions would be necessary if these requirements are not satisfied, or if this program fails to meet the requirements of 10 CFR Part 50, Appendix H. If plant operating characteristics exceed the operating restrictions identified previously, such as a lower reactor vessel operating temperature or higher neutron fluence, this program provides reasonable assurance that the impact of actual plant operation characteristics on the extent of reactor vessel embrittlement is evaluated, and the NRC is notified.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The existing reactor vessel material surveillance program provides sufficient material data and dosimetry to (1) monitor irradiation embrittlement at the end of the subsequent period of extended operation, and (2) determine the need for operating restrictions on the inlet temperature, neutron fluence, and neutron flux.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR Part 50, Appendix G, "Fracture Toughness Requirements." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." Washington, DC: U.S. Nuclear Regulatory Commission. 2015. 10 CFR Part 50-TN249

10 CFR 50.61a, "Alternate Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." Washington, DC: U.S. Nuclear Regulatory Commission. 2015. 10 CFR Part 50-TN249

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XI.M32 ONE-TIME INSPECTION

Program Description

A one-time inspection of selected components is conducted just prior to the beginning of a subsequent period of extended operation (e.g., prior to the second period of extended operation) in order to verify the system-wide effectiveness of an aging management program (AMP) that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the subsequent period of extended operation. For example, effective control of water chemistry under the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M2, “Water Chemistry” program can prevent some aging effects and minimize others. However, there may be locations that are isolated from the flow stream for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. This program provides inspections that verify that unacceptable degradation is not occurring.

This program can also be used to verify the lack of significance of an aging effect. Situations in which additional confirmation is appropriate include (1) an aging effect is not expected to occur, but the data are insufficient to rule it out with reasonable confidence; or (2) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than generally expected. For these cases, confirmation demonstrates that either the aging effect is not occurring or that the aging effect is occurring very slowly and does not affect the component’s or structure’s intended function during the subsequent period of extended operation based on date derived from prior operating experience (OE).

In addition, for steel components exposed to water environments that do not include corrosion inhibitors as a preventive action (e.g., treated water, treated borated water, raw water, waste water), this program verifies that long-term loss of material due to general corrosion will not cause a loss of intended function (e.g., pressure boundary, leakage boundary [spatial], structural integrity [attached]).

This program does not address Class 1 piping of less than 4 inches nominal pipe size. That piping is addressed in GALL-SLR Report AMP XI.M35, “ASME Code Class 1 Small-Bore Piping.”

The elements of the program include (1) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environments, plausible aging effects, and OE; (2) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (4) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the subsequent period of extended operation.

The program may include a review of routine maintenance, repair, or inspection records to confirm that selected components have been inspected for aging degradation within the recommended time period for the inspections related to the subsequent period of extended operation, and that significant aging degradation has not occurred. A one-time inspection program is acceptable to verify the effectiveness of GALL-SLR Report AMP XI.M2, “Water Chemistry,” GALL-SLR Report AMP XI.M30, “Fuel Oil Chemistry,” and GALL-SLR Report

AMP XI.M39, “Lubricating Oil Analysis,” when the environment in the subsequent period of extended operation is expected to be equivalent to that in the prior operating period and for which no aging effects have been observed. However, the one-time inspection for environments that do not fall in the above category, or of any other action or program created to verify the effectiveness of an AMP and confirm the absence of an aging effect, is to be reviewed by the staff on a plant-specific basis.

This program cannot be used for structures or components with known age-related degradation mechanisms or when the environment in the subsequent period of extended operation is not expected to be equivalent to that in the prior operating period. Periodic inspections are proposed in these cases.

Evaluation and Technical Basis

1 ***Scope of Program:*** The scope of this program includes systems and components that are subject to aging management using GALL-SLR Report AMPs XI.M2, “Water Chemistry;” XI.M30, “Fuel Oil Chemistry;” and XI.M39, “Lubricating Oil Analysis;” and for which no aging effects have been observed or for which the aging effect is occurring very slowly and will not affect the component’s or structure’s intended function during the subsequent period of extended operation based on prior OE data. The scope of this program also may include other components and materials for which the environment in the subsequent period of extended operation is expected to be equivalent to that during the prior operating period and for which no aging effects have been observed. The scope of this program includes managing long-term loss of material due to general corrosion of steel components. Long-term loss of material due to general corrosion of steel components need not be managed if one of the following two conditions is met: (1) the environment for the steel components includes corrosion inhibitors as a preventive action; or (2) wall thickness measurements of a representative sample of each environment will be conducted between the 50th and 60th year of operation. Environments such as treated water, treated borated water, raw water, and waste water do not typically include corrosion inhibitors.

The program cannot be used for structures or components

- subjected to known age-related degradation mechanisms as determined based on a review of plant-specific and industry OE for the prior operating period,
- when the environment in the subsequent period of extended operation is not expected to be equivalent to that in the prior operating period, or
- when aging effects that do not meet the acceptance criteria are identified during the one-time inspection conducted in the prior operating period or during the review of plant-specific or industry OE.

Periodic inspections are proposed in these cases.

2 ***Preventive Actions:*** One-time inspection is a condition monitoring program. It does not include methods for mitigating or preventing age-related degradation.

3 ***Parameters Monitored or Inspected:*** The program monitors parameters directly related to the age-related degradation of a component. Examples of parameters monitored and the related aging effects are provided in Table XI.M32-1, “Examples of Parameters Monitored or Inspected and Aging Effect for Specific Structure or Component.” Inspection is performed using a variety of nondestructive examination (NDE) methods, including visual, volumetric, and surface techniques.

Table XI.M32-1. Examples of Parameters Monitored or Inspected and Aging Effect for Specific Structure or Component[(a)]

Aging Effect	Aging Mechanism	Parameter(s) Monitored	Inspection Method[(b)]
Loss of Material	Crevice Corrosion	Surface Condition or Wall Thickness	Visual (e.g., VT-1) or Volumetric (e.g., UT)
Loss of Material	General Corrosion	Surface Condition or Wall Thickness	Visual (e.g., VT-3) or Volumetric (e.g., UT)
Loss of Material	Microbiologically influenced Corrosion	Surface Condition or Wall Thickness	Visual (e.g., VT-3) or Volumetric (e.g., UT)
Loss of Material	Pitting Corrosion	Surface Condition or Wall Thickness	Visual (e.g., VT-1) or Volumetric (e.g., UT)
Long-term Loss of Material	General Corrosion	Wall Thickness	Volumetric (e.g., UT)
Reduction of Heat Transfer	Fouling	Tube Fouling	Visual (e.g., VT-3)
Cracking	SCC or Cyclic Loading	Surface Condition or Cracks	Enhanced Visual (e.g., EVT-1) or Surface Examination (magnetic particle, liquid penetrant) or Volumetric (radiographic testing or UT)

(a) The examples provided in this table may not be appropriate for all relevant situations. If the applicant chooses to use an alternative to the recommendations in this table, a technical justification is provided as an exception to this AMP. This exception lists the aging management review line item component, examination technique, acceptance criteria, evaluation standard, and a description of the justification.
(b) Visual inspection may be used only when the inspection methodology examines the surface potentially experiencing the aging effect.

4 ***Detection of Aging Effects:*** Elements of the program include (1) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and OE; (2) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; and (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined.

The inspection includes a representative sample of each population (defined as components having the same material, environment, and aging effect combination) and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, and the severity of operating conditions. A representative sample size is 20 percent of the population or a maximum of 25 components at each unit. Otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection is included as part of the program’s documentation.

The program relies on established NDE techniques, including visual, ultrasonic, and surface techniques. Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the type of examination specified. Inspections and tests within the scope of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code)[1] follow procedures consistent with the ASME Code. Non-ASME

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

Code inspections follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. In addition, a description of enhanced visual examination (EVT)-1 is found in the Boiling Water Reactor Vessel and Internals Project (BWRVIP)-03 and the Materials Reliability Program (MRP)-228.

When using this AMP to conduct one-time inspections of aluminum piping, piping components and tanks exposed to air, aluminum structures and components (SCs) are grouped by material type. The high-strength heat treatable aluminum alloys (i.e., 2xxx and 7xxx series) may be treated as a separate population when performing inspections and interpreting results due to their relatively lower corrosion resistance. The relative susceptibility of moderate and lower strength alloys varies based on composition (primarily weight percent Cu, Mg, and Fe) and temper designation. Grouping of air environments consistent with the Detection of Aging Effects program element of GALL-SLR Report AMP XI.M38 is acceptable.

In addition, when using this AMP to conduct inspections of stainless steel (SS), nickel alloy, and aluminum components exposed to any air environment or condensation to detect loss of material or stress corrosion cracking, the internal surfaces of these components do not need to be inspected if (1) the review of plant-specific OE does not reveal a history of pitting or crevice corrosion, and (2) inspection results for external surfaces demonstrate that the aging effect is not applicable. Inspection results associated with the periodic introduction of either moisture or halides from secondary sources (e.g., leaking flanges) may be treated as a separate population of components.

An inspection of a component in a more severe environment may be credited as an inspection for the specified environment and for the same material and aging effects in a less severe environment (e.g., a high-humidity environment is more severe than an indoor controlled air environment because the moisture in the former environment is more likely to result in aging effects than would be expected from the normally dry surfaces associated with the latter environment). Alternatively, similar environments (e.g., internal uncontrolled indoor, controlled indoor, dry air environments) can be combined into a larger population if the inspections occur on components located in the most severe environment (e.g., in the locality of flanges that have leaked in the past).

For managing long-term loss of material, exceptions need not be stated for the following:

- Conducting wall thickness measurements for long-term loss of material in a different AMP (e.g., AMP XI.M20) as long as the alternative AMP cites the necessary detail (e.g., environment, sample size, purpose of inspection).
- Use of the data from recurring internal corrosion wall thickness measurements as long as the material and environment is consistent with that for long-term loss of material.
- Use of scanning techniques (e.g., low-frequency electromagnetic testing) as long as the method, coverage, and threshold for follow-up wall thickness measurements when indications are detected are stated in the subsequent license renewal application.

With respect to inspection timing, the sample of components are inspected before the end of the current operating term to provide reasonable assurance that the aging effect will not compromise any intended function during the subsequent period of extended operation. Inspections need to be timed to allow the inspected components to attain sufficient age such that the aging effects with long incubation periods (i.e., those that may affect intended functions near the end of the subsequent period of extended operation) are identified. Within these constraints, the applicant schedules the inspection no earlier than 10 years prior to the subsequent period of extended operation. For recently installed repairs/replacements that may not be bounded by other population samples, the one-time inspection should be performed after sufficient operational exposure to provide reasonable confidence in inspection results.

5 ***Monitoring and Trending:*** Inspection results for each material, environment, and aging effect are compared to those obtained during previous inspections when available. Where practical, these results are trended to project observed degradation to the end of the subsequent period of extended operation.

6 ***Acceptance Criteria:*** The acceptance criteria for this program consider both the results of observed degradation during current inspections and the results of projecting observed degradation of the inspections for each material, environment and aging effect combinations.

- Any indications or relevant conditions are evaluated. Acceptance criteria may be based on the applicable ASME Code or other appropriate standards, design basis information, or vendor-specified requirements and recommendations (e.g., ultrasonic thickness measurements are compared to predetermined limits); however, crack-like indications are not acceptable.

- When it is practical to project observed degradation to the end of the subsequent period of extended operation, the projected degradation will not (1) affect the intended function of a system, structure, or component; (2) result in a potential leak; or (3) result in heat transfer rates below that required by the current licensing basis to meet design limits.

When measurable degradation has occurred, but acceptance criteria have been met, the inspection results are entered into the applicant’s corrective action program for future monitoring and trending.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

If the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement of all components constructed of the same material and exposed to the same environment, additional inspections are conducted if one of the inspections does not meet the acceptance criteria. The number of increased inspections is determined in accordance with the site’s corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet the acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. If subsequent inspections do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections needed. At multi-unit sites, the additional inspections include inspections at all of the units that have the same material, environment, and aging effect combination.

Where an aging effect identified during an inspection does not meet the acceptance criteria or projected results of the inspections of a material, environment, and aging effect combination do not meet the above acceptance criteria, a periodic inspection program is developed for the specific material, environment, and aging effect combination. The periodic inspection program is implemented at all of the units on the site that have same combination(s) of material, environment, and aging effect.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The elements that comprise inspections associated with this program (the scope of the inspections and inspection techniques) are consistent with industry practice. An applicant's OE with detection of aging effects should be adequate to demonstrate that the program is capable of detecting the presence or noting the absence of aging effects in the components, materials, and environments when one-time inspection is used to confirm system-wide effectiveness of another preventive or mitigative AMP.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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10 CFR 50.55a, "Codes and Standards. Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

ASME. ASME Code Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." New York, New York: The American Society of Mechanical Engineers. 2008.[2]

EPRI. BWRVIP-03, Revision 6 (EPRI 105696-R6), "BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines." Agencywide Documents Access and Management System Accession No. ML040440261. Palo Alto, California: Electric Power Research Institute. December 2003.

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[2] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

XI.M33 SELECTIVE LEACHING

Program Description

This program for selective leaching (dealloying) of materials includes components made of gray cast iron, ductile iron, malleable iron, and copper alloys (except for inhibited brass) that contain more than 15 percent zinc or more than 8 percent aluminum exposed to a raw water, closed-cycle cooling water (CCCW), treated water, waste water, or soil environment. Depending on the environment, the aging management program (AMP) includes one-time, or opportunistic or periodic visual, inspections of selected components that are susceptible to selective leaching, coupled with mechanical examination techniques (e.g., chipping, scraping). Destructive examinations of components to determine the presence and depth of dealloying through-wall thickness are also conducted. These techniques can determine whether loss of material due to selective leaching is occurring and whether selective leaching will affect the ability of the components to perform their intended function for the subsequent period of extended operation.

The selective leaching process involves the preferential removal of one of the alloying components from the material. Dezincification (loss of zinc from brass) and graphitization or graphitic corrosion (removal of iron from gray cast iron, ductile iron, and malleable iron) are examples of such a process. Susceptible materials exposed to high operating temperatures, stagnant-flow conditions, and a corrosive environment (e.g., acidic solutions for brasses with high zinc content and dissolved oxygen) are conducive to selective leaching. A dealloyed component often retains its shape and may appear to be unaffected; however, the functional cross section of the material has been reduced. The aging effect attributed to selective leaching is loss of material because the affected volume has a permanent change in density and does not retain mechanical properties that can be credited for structural integrity.

Evaluation and Technical Basis

1 ***Scope of Program:*** Components include piping, valve bodies and bonnets, pump casings, and heat exchanger components that are susceptible to selective leaching. The materials of construction for these components may include gray cast iron, ductile iron, malleable iron, and copper alloys (except for inhibited brass) containing more than 15 percent zinc or more than 8 percent aluminum. These components may be exposed to raw water, CCCW, treated water, waste water, or soil.

Depending on plant-specific operating experience (OE) and the implementation of preventive actions, certain components may be excluded from the scope of this program in each 10-year inspection interval, as follows:

- The internal surfaces of internally coated components for which loss of coating integrity is managed by Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks.”
- The external surfaces of buried gray cast iron, ductile iron, and malleable iron components that have been cathodically protected since their installation and meet the criteria for Preventive Actions Category C in GALL-SLR Report AMP XI.M41, Table XI.M41-2, “Inspections of Buried and Underground Piping and Tanks.”
- The external surfaces of buried copper alloy components that meet the above cathodic protection recommendations, if a technical justification is submitted with the subsequent

license renewal application (SLRA) that demonstrates the effectiveness of cathodic protection in the prevention of selective leaching for those alloys.

2 ***Preventive Actions:*** Although the program does not provide guidance about preventive actions, water chemistry control of certain parameters (e.g., pH, concentration of corrosive contaminants, dissolved oxygen), cathodic protection, and coatings can be effective in minimizing selective leaching.

3 ***Parameters Monitored or Inspected:*** This program monitors visual appearance (e.g., color, porosity, abnormal surface conditions), surface conditions through mechanical examination techniques (e.g., chipping, scraping), and the presence and depth of dealloying through-wall thickness through destructive examinations.

4 ***Detection of Aging Effects:*** Inspections and examinations consist of the following:

- Visual inspections of all accessible surfaces. In certain copper-based alloys selective leaching can be detected by visual inspection through a change in color from a normal yellow color to a reddish copper color or green copper oxide. Graphitized cast iron cannot be reliably identified through visual examination, because the appearance of the graphite surface layer created by selective leaching does not always differ appreciably from the typical cast iron surface.
- Mechanical examination techniques, such as chipping and scraping, augment visual inspections for gray cast iron, ductile iron, and malleable iron components.
- Destructive examinations used to determine the presence and depth of dealloying through-wall thickness of components.

One-time and periodic inspections are conducted of a representative sample of each population. A population is defined as the same material and environment combination. Due to similarities in microstructure, ductile and malleable iron may be grouped together in sample populations. Opportunistic inspections are conducted whenever components are opened, or buried or submerged surfaces are exposed.

One-time inspections are only conducted for components exposed to CCCW or treated water when no plant-specific OE of selective leaching exists in these environments. In the 10-year period prior to a subsequent period of extended operation, a sample of 3 percent of the population or a maximum of 10 components per population at each unit are visually and mechanically (for gray cast iron, ductile iron, and malleable iron components) inspected. Inspections, where possible, focus on the bounding or lead components most susceptible to aging based on their time in service and the severity of operating conditions for each population.

Opportunistic and periodic inspections are conducted for components exposed to raw water, waste water, or soil, and for components in CCCW or treated water where plant-specific OE includes selective leaching in these environments. Opportunistic inspections are conducted whenever components are opened, or buried or submerged surfaces are exposed. Periodic inspections are conducted in the 10-year period prior to a subsequent period of extended operation and in each 10-year period during a subsequent period of extended operation. Additional details about opportunistic and periodic inspections are as follows:

- If the inspection conducted for ductile iron or malleable iron in the 10-year period prior to a subsequent period of extended operation (i.e., the initial inspection) meets the acceptance criteria, periodic inspections do not need to be conducted during the subsequent period of extended operation for ductile iron or malleable iron.

- A sample of 3 percent of the population or a maximum of 10 components per population is visually and mechanically (for gray cast iron,ductile iron, and malleable iron components) inspected at each unit.
- For sites with gray cast iron piping exposed to soil, a sample of 20 percent of the population with a maximum of 25 components is visually and mechanically inspected at each unit; a reduction in the sample size is supported by a technical justification submitted with the SLRA (e.g., based on results from inspections previously conducted).
- When inspections are conducted on piping, inspection of a 1-foot axial length section is considered to be one inspection. Samples are taken from multiple locations to ensure that a representative sample is examined, focusing on the components most susceptible to selective leaching.
- For sample populations with more than 35 susceptible components, two destructive examinations are performed in each material and environment population in each 10-year period at each unit. When there are fewer than 35 susceptible components in a sample population, one destructive examination is performed for that population. Otherwise, a technical justification of the methodology and sample size used for selecting components for inspection is included as part of the program's documentation.
- The number of visual and mechanical inspections may be reduced by two for each component that is destructively examined beyond the minimum number of destructive examinations recommended to occur during each 10-year interval.
- Inspections, where possible, focus on the bounding or lead components most susceptible to aging based on their time in service and the severity of operating conditions for each population.
- Opportunistic inspections may be credited as periodic inspections as long as the inspection location selection criteria are met.

For multi-unit sites where the sample size is not based on the percentage of the population and the inspections are conducted periodically (not one-time inspections), it is acceptable to reduce the total number of inspections at the site as follows. For two unit sites, eight visual and mechanical inspections and two destructive examinations are conducted at each unit. For two unit sites with fewer than 35 susceptible components in a sample population at each unit, one destructive examination is performed for that sample population. For three unit sites, seven visual and mechanical and one destructive examination are conducted at each unit. To conduct the reduced number of inspections, the applicant states in the SLRA the basis for why the operating conditions at each unit are similar enough (e.g., flowrate, chemistry, temperature, excursions) to provide representative inspection results. The basis should include consideration of potential differences such as the following:

- Have power uprates been performed and if so, could more aging have occurred on one unit that has been in the uprate period for a longer time period?
- Have any systems had an out-of-spec water chemistry condition for a longer period of time or out-of-spec conditions that occurred more frequently?
- For raw water systems, is the water derived from different sources where one or the other is more susceptible to microbiologically influenced corrosion or other aging effects?
- For buried components, has soil corrosivity testing demonstrated that relevant parameters (e.g., soil resistivity, pH, chlorides, moisture) are consistent across the site?

For raw water and wastewater environments, the populations may be combined as long as an evaluation is conducted to determine the more severe environment, and the inspections and examinations are conducted on components in the most severe environment, with one inspection being conducted in the less severe environment.

Inspections follow site procedures that include inspection parameters such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

5 ***Monitoring and Trending:*** Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

6 ***Acceptance Criteria:*** The acceptance criteria are (1) for copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide; (2) for gray cast iron, ductile iron, and malleable iron, the absence of a surface layer that can be easily removed by chipping or scraping or identified in the destructive examinations; (3) the presence of no more than a superficial layer of dealloying, as determined by removal of the dealloyed material by mechanical removal; and (4) the components meet system design requirements such as minimum wall thickness, when extended to the end of the subsequent period of extended operation. When evaluating a component in relation to criterion (3) no credit is used for the material properties of the dealloyed portion of the component.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and component (SCs) within the scope of this program.

When the acceptance criteria are not met, such that it is determined that the affected component should be replaced prior to the end of the subsequent period of extended operation, additional inspections are performed if the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement of all components constructed of the same material and exposed to the same environment. The number of additional inspections is equal to the number of failed inspections for each material and environment population with a minimum of five additional visual and mechanical inspections when visual and mechanical inspections(s) did not meet the acceptance criteria, or 20 percent of each applicable material and environment combination is inspected, whichever is less, and a minimum of one additional destructive examination when destruction examination(s) did not meet the acceptance criteria. If subsequent inspections do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections needed. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, in all cases, the additional inspections are completed within the interval during which the original inspection was conducted or, if identified during the latter half of the current inspection interval, within the next refueling outage interval. The additional inspections conducted during the next inspection interval cannot also be credited toward the number of inspections in the latter interval. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. At multi-unit sites, the additional inspections include inspections at all of the units that have the same material, environment, and aging effect combination.

The program includes a process for evaluating difficult-to-access surfaces (e.g., heat exchanger shell interiors, exterior of heat exchanger tubes) if unacceptable inspection findings occur within the same material and environment population.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** OE shows that selective leaching has been detected in components constructed from gray cast iron, ductile iron, malleable iron, brass, bronze, and aluminum bronze. The following OE may be of significance to an applicant’s program:

a. In March 2013, a licensee submitted an American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Section XI relief request because it had detected weeping through aluminum bronze (susceptible to dealloying) valve bodies exposed to seawater. The degraded area was characterized by corrosion debris or wetness that returned after cleaning and drying of the surface. (Agencywide Documents Access and Management System [ADAMS] Accession No. ML13091A038 and ML14182A634).

b. During a one-time inspection for selective leaching, a licensee identified degradation in four gray cast iron valve bodies in the service water system exposed to raw water. The mechanical test used by the licensee to identify the graphitization was tapping and scraping of the surface. The licensee sandblasted two of the valve bodies and, after all of the graphite was removed, the licensee determined that the leaching progressed to a depth of approximately 3/32 inch. Based on the estimated corrosion rate, the licensee determined that the valve bodies had adequate wall thickness for at least 20 years of additional service (ADAMS Accession No. ML14017A289).

c. Based on visual inspections conducted as part of implementing a one-time inspection for selective leaching, a licensee identified selective leaching in a gray cast iron drain plug of an auxiliary feedwater pump outboard bearing cooler. Possible selective leaching was also found on multimatic valves on the underside of the clapper. As a result, the licensee incorporated quarterly inspections of the components in its periodic surveillance and preventive maintenance program (ADAMS Accession No. ML13122A009).

d. In September 2008, a licensee identified the dealloying of an aluminum bronze strainer drum exposed to brackish water. This was identified after an unexpected material failure occurred during a planned maintenance evolution at an offsite repair facility. The maintenance evolution involved rigging the strainer drum into position for a machining operation. During the rigging, the strainer drum material failed at the rigging attachment point to the strainer. This failure of the strainer drum exposed the inner portion of the drum material where dealloying of the drum was visually observed during an inspection (ADAMS Accession No. ML092400531). A licensee has reported occurrences of selective leaching of aluminum bronze components for an extensive number of years (ADAMS Accession No. ML17142A263). The licensee is evaluating changes to its current approach to managing selective leaching in order to address the aging effect during the period of extended operation.

e. NRC IN 94-59, Accelerated Dealloying of Cast Aluminum-Bronze Valves Caused by Microbiologically Induced Corrosion, August 17, 1994.

f. The basis for inclusion of ductile iron in this GALL-SLR Report AMP XI.M33, along with OE examples, is cited in the GALL-SLR and SRP-SLR Supplemental Staff Guidance document (ADAMS Accession No. ML16041A090).

g. In July 2019, two ruptures occurred in buried gray cast iron piping associated with the fire protection system (ADAMS Accession No. ML19294A044). The cause of the ruptures was determined to be long-standing exposure to moist or wet soil, which resulted in external corrosion and subsequent reduction in wall thickness at these locations. A follow-up submittal (ADAMS Accession No. ML19310E716) clarified that the aging mechanism was graphitic corrosion (i.e., selective leaching).

h. NRC IN 20-04, Operating Experience Regarding Failure of Buried Fire Protection Main Yard Piping, December 17, 2020.

i. In October 2021, a licensee identified graphitic corrosion on the internal surfaces of cross-sectioned malleable iron pipe fittings. The internal environment was close-cycled cooling water (ADAMS Accession No. ML22010A129).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

EPRI. EPRI TR–107514, “Age Related Degradation Inspection Method and Demonstration.” Palo Alto, California: Electric Power Research Institute. April 1998.

Fontana, M.G. *Corrosion Engineering*. McGraw Hill. pp. 86-90. 1986.

NRC. “GALL-SLR and SRP-SLR Supplemental Staff Guidance.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML16041A090. Washington, DC: U.S. Nuclear Regulatory Commission. March 2016.

XI.M35 ASME CODE CLASS 1 SMALL-BORE PIPING

Program Description

This program is a condition monitoring program for detecting cracking in small-bore, American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code)[1] Class 1 piping. The program augments the inservice inspections (ISIs) specified by ASME Code, Section XI, for certain ASME Code Class 1 piping that is of less than 4 inches nominal pipe size (NPS) and greater than or equal to 1 inch NPS.

Industry operating experience (OE) demonstrates that welds in ASME Code Class 1 small-bore piping are susceptible to stress corrosion cracking (SCC) and cracking due to thermal or vibratory fatigue loading. Such cracking is frequently initiated from the inside diameter of the piping; therefore, volumetric examinations are needed to detect cracks. However, ASME Code, Section XI, generally does not call for volumetric examinations of this class and size of piping. Specifically, ASME Code, Section XI, Subarticle IWB-1220, exempts all components that are less than or equal to 1 inch NPS from volumetric examinations. In addition, with the exception of certain pressurized water reactor high-pressure safety injection system piping components, ASME Code, Section XI, Table IWB-2500-1, calls for surface examinations and visual inspections during system leakage tests of piping components that are less than 4 inches NPS.

This program supplements the ASME Code, Section XI, examinations with volumetric examinations, or alternatively, destructive examinations, to detect cracks that may originate from the inside diameter of butt welds, socket welds, and their base metal materials. The examination schedule and extent is based on plant-specific OE and whether actions have been implemented that would successfully mitigate the causes of any past cracking. The program relies on a sample size as specified in Table XI.M35-1 as a means of determining whether cracking is occurring in the total population of ASME Code Class 1 small-bore piping in the plant.

Evaluation and Technical Basis

1. ***Scope of Program:*** This program manages the effects of SCC and cracking due to thermal or vibratory fatigue loading for certain ASME Code Class 1 small-bore piping. For the purposes of this program, small-bore piping includes piping that is less than 4 inches NPS and greater than or equal to 1 inch NPS.

2. ***Preventive Actions:*** This is a condition monitoring program only; therefore, it has no preventive actions.

3. ***Parameters Monitored or Inspected:*** Cracking is detected through either destructive or nondestructive examinations of piping welds and base metal materials. The volume of these materials is examined to detect flaws or other discontinuities that may indicate the presence of cracks.

4. ***Detection of Aging Effects:*** A sample of ASME Code Class 1 small-bore piping welds is examined in accordance with the categories specified in Table XI.M35-1. The initial schedule of examinations, either one time for Categories A and B or periodically for Category C, is based on plant-specific OE and whether actions that would successfully

[1] GALL-SLR Report. Chapter 1, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

mitigate the causes of any past cracking have been implemented. Periodic examinations are implemented in accordance with Category C if the one-time examinations detect any unacceptable flaws or relevant conditions. The scope of the examinations includes both full penetration (butt) welds and partial penetration (socket) welds.

The welds to be examined are selected from the locations determined to be the most risk significant and most susceptible to SCC and cracking due to thermal or vibratory fatigue loading. Other factors, such as plant-specific and industry OE, accessibility, and personnel exposure, can also be considered to select the most appropriate locations for the examinations. The guidelines from Electric Power Research Institute (EPRI) Technical Report 1011955, “Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146),” and EPRI Technical Report 1018330, “Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines–Supplemental Guidance (MRP-146S),” may be used to determine the locations that are most susceptible to thermal fatigue. Because more information can be obtained from a destructive examination than from a nondestructive examination, the applicant can take credit for each weld destructively examined as being equivalent to having volumetrically examined two welds.

Table XI.M35-1. Examinations

Category	Plant Operating Experience	Mitigation	Examination Schedule	Sample Size	Examination Method
A	No age-related cracking[(a.b)]	Not applicable	One-time: completed within 6 years prior to the start of the subsequent period of extended operation	Full penetration (butt) welds: 3% of total population per unit, up to 10[(c)] Partial penetration (socket) welds: 3% of total population per unit, up to 10[(d)]	Volumetric or destructive[(e, f)]
B	Age-related cracking[(b)]	Yes[(e)]	One-time: completed within 6 years prior to the start of the subsequent period of extended operation	Full penetration (butt) welds: 10% of total population per unit, up to 25[(d)] Partial penetration (socket) welds: 10% of total population per unit, up to 25[(d)]	Volumetric or destructive[(e, f)]

Category	Plant Operating Experience	Mitigation	Examination Schedule	Sample Size	Examination Method
C	Age-related cracking[b]	No	Periodic: first examination completed within the 6 years prior to the start of the subsequent period of extended operation with subsequent examinations every 10 years thereafter	Full penetration (butt) welds: 10% of total population per unit, up to 25[d] Partial penetration (socket) welds: 10% of total population per unit, up to 25[d]	Volumetric or destructive[e, f]

(a) Must have no history of age-related cracking.
(b) Age-related cracking includes piping leaks or other flaws where fatigue or stress corrosion cracking are contributing factors.
(c) Actions must have been taken to mitigate the cause of the cracking. These actions, such as design changes, would generally go beyond typical repair or replacement activities. For welds that have been redesigned or repaired and for which the applicant can demonstrate through operating experience (OE) that no additional failures have been reported for the last 30 years, then the inspection sample size could follow the guidance in Category A.
(d) The welds to be examined are selected from locations that are determined to be the most risk significant and most susceptible to cracking. Other factors, such as plant-specific and industry OE, accessibility, and personnel exposure, can also be considered when selecting the most appropriate locations for the examinations.
(e) Volumetric examinations must employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest.
(f) Each partial penetration (socket) weld subject to destructive examination may be credited twice toward the total number of examinations because more information can be obtained from a destructive examination than from a nondestructive examination.

5 ***Monitoring and Trending:*** For plants that are in Category A or B, a one-time examination provides confirmation that cracking is not occurring or that it is occurring so slowly that it will not affect the component's intended function during the subsequent period of extended operation. Periodic examinations provide for the timely detection of cracks for plants that are in Category C. If a component containing flaws or relevant conditions is accepted for continued service by analytical evaluation, then it is subsequently reexamined to meet the intent of ASME Code, Section XI, Subarticle IWB-2420.

6 ***Acceptance Criteria:*** Examination results are evaluated in accordance ASME Code, Section XI, Paragraph IWB-3132.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

The corrective actions are to include examinations of additional ASME Code Class 1 small-bore piping welds to meet the intent of ASME Code, Section XI, Subarticle IWB-2430. In addition, for the plants that are either in Categories A or B, periodic examinations are then implemented in accordance with the schedule specified in Category C.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls*****:** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Through-wall cracking in ASME Code Class 1 small-bore piping has occurred at a number of plants. Causes include SCC and thermal and vibratory fatigue loading as described in the U.S. Nuclear Regulatory Commission Information Notice 97-46, “Unisolable Crack in High-Pressure Injection Piping.” This program augments the ASME Code, Section XI, inspections to provide assurance that cracks will be detected before there is a loss of intended function. Licensee Event Reports (LERs) 259/2008-002 and LER 387/2012-007-00 provide a sample of relevant OE.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

ASME. ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” New York, New York: The American Society of Mechanical Engineers. 2008.

EPRI. Technical Report 1011955, “Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146).” Palo Alto, California: Electric Power Research Institute. June 2005.

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Licensee Event Report 259/2008-002 and LER 259/2008-002-01, “ASME Code Class 1 Pressure Boundary Leak on an Instrument Line Connected to the Reactor Vessel.” https://lersearch.inl.gov/LERSearchCriteria.aspx. March 2009.

Licensee Event Report 387/2012-007-00, “Unplanned Shutdown Due to Unidentified Drywell Leakage.” https://lersearch.inl.gov/LERSearchCriteria.aspx. September 2012.

NRC. Information Notice 97-46, “Unisolable Crack in High-Pressure Injection Piping.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1997.

XI.M36 EXTERNAL SURFACES MONITORING OF MECHANICAL COMPONENTS

Program Description

The External Surfaces Monitoring of Mechanical Components program is based on system inspections and walkdowns. It consists of periodic visual inspections of metallic, polymeric, and cementitious components, such as piping, piping components, ducting, ducting components; heating, ventilation, and air conditioning (HVAC) closure bolting; heat exchanger components; and seals. The program manages aging effects through visual inspection of external surfaces for evidence of loss of material, cracking, hardening or loss of strength, reduced thermal insulation resistance, loss of preload for HVAC closure bolting, and reduction of heat transfer due to fouling. When appropriate for the component and material (e.g., elastomers, flexible polymers, polyvinyl chloride), physical manipulation is used to augment visual inspection to confirm the absence of hardening or loss of strength, or reduction in impact strength. This program may also be used to manage cracking due to stress corrosion cracking (SCC) in aluminum and stainless steel (SS) components exposed to aqueous solutions and air environments containing halides.

Reduced thermal insulation resistance due to moisture intrusion, associated with insulation that is jacketed, is managed by visual inspection of the condition of the jacketing when the insulation has an intended function to reduce heat transfer from the insulated components. Outdoor insulated components, and indoor components exposed to condensation, have portions of the insulation inspected or removed, when applicable, to determine whether the exterior surface of the component is degrading or has the potential to degrade. Loss of material due to boric acid corrosion is managed by the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M10, “Boric Acid Corrosion.”

Evaluation and Technical Basis

1 ***Scope of Program:*** This program visually inspects the external surfaces of mechanical components. The program also inspects heat exchanger surfaces exposed to air for evidence of reduction of heat transfer due to fouling.

For situations in which the similarity of the internal and external environments is such that the external surface condition is representative of the internal surface condition, external inspections of components may be credited for managing (1) the loss of material and cracking of internal surfaces for metallic and cementitious components, (2) the loss of material and cracking of internal surfaces for polymeric components, and (3) the hardening or loss of strength of internal surfaces for elastomeric components. When credited, the program provides the basis for establishing that the external and internal surface condition and environment are sufficiently similar.

Aging effects associated with underground piping and tanks that are below grade but are contained within a tunnel or vault, such that they are in contact with air and are located where access for inspection is restricted, are managed by GALL-SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks.” Aging effects associated with below-grade components that are accessible during normal operations or refueling outages for which access is not restricted are managed by this program.

2 ***Preventive Actions:*** Depending on the material, components may be coated to mitigate corrosion by protecting the external surface of the component from environmental exposure.

Inspections to verify the integrity of the insulation jacketing can limit or prevent water inleakage in the insulation.

3 ***Parameters Monitored or Inspected:*** This program uses periodic plant system inspections and walkdowns to monitor for material degradation, accumulation of debris, and leakage. The program inspects components such as piping, piping components, ducting, seals, insulation jacketing, and air-side heat exchangers. For metallic components, coating deterioration is an indicator of possible underlying degradation. Cementitious components are visually inspected for indications of loss of material and cracking. Periodic visual or surface examinations are conducted if this program is being used to manage cracking in SS or aluminum components.

Examples of inspection parameters for metallic components include the following:

- corrosion and surface imperfections (loss of material or cracking)
- loss of wall thickness (loss of material)
- flaking of oxide-coated surfaces (loss of material)
- corrosion stains on thermal insulation (loss of material)
- cracking, flaking, or blistering of protective coating (loss of coating integrity)
- leakage for detection of cracks on the surfaces of SS and aluminum components exposed to air and aqueous solutions containing halides (cracking)
- accumulation of debris on heat exchanger tube surfaces (reduction of heat transfer).

The aging effects for elastomeric and flexible polymeric components are monitored through a combination of visual inspection and manual or physical manipulation of the material. Manual or physical manipulation of the material includes touching, pressing on, flexing, bending, or otherwise manually interacting with the material. The purpose of the manual manipulation is to reveal changes in material properties, such as hardness, and to make the visual examination process more effective in identifying aging effects such as cracking. Flexing of polyvinyl chloride piping exposed directly to sunlight (i.e., not located in a structure restricting access to sunlight such as manholes, enclosures, and vaults or isolated from the environment by coatings) is conducted to detect the potential reduction in its impact strength, as indicated by a crackling sound or surface cracks when flexed.

Examples of inspection parameters for elastomers and polymers include the following:

- surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”)
- loss of thickness
- discoloration (evidence of a potential change in material properties that could be indicative of polymeric degradation)
- exposure of internal reinforcement for reinforced elastomers
- hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation.

Examples of inspection parameters for cementitious materials include

- spalling
- scaling

- cracking.

4 ***Detection of Aging Effects:*** This program manages the aging effects of loss of material, cracking, hardening or loss of strength, reduced thermal insulation resistance, loss of preload for HVAC closure bolting, and reduction of heat transfer due to fouling using visual inspections. In addition, physical manipulation is used to manage hardening or loss of strength and reduction in impact strength. For coated surfaces, confirmation of the integrity of the coating is an effective method for managing the effects of corrosion on the metallic surface.

Inspections are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. When required by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), inspections are conducted in accordance with the applicable code requirements. Non-ASME Code inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, and presence of protective coatings. The inspections are capable of detecting age-related degradation and, with the exception of examinations to detect cracking in SS or aluminum components, are performed at a frequency not to exceed one refueling cycle. This frequency accommodates inspections of components that may be in locations normally accessible only during outages (e.g., high-dose areas). Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

Periodic visual inspections or surface examinations are conducted on SS and aluminum components to manage cracking every 10 years during the subsequent period of extended operation when applicable (e.g., see Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR) Sections 3.2.2.2.4 and 3.2.2.2.8). One or more of the following three options may be used to implement the periodic visual inspections or surface examinations:

- Surface examination conducted in accordance with plant-specific procedures.
- ASME Code Section XI VT-1 inspections (including inspections conducted on non-ASME Code components).
- Visual inspections may be conducted when it has been analytically demonstrated that surface cracks can be detected by leakage prior to a crack challenging the structural integrity or intended function of the component. The subsequent license renewal application (SLRA) includes an overview of the analytical method, input variables, assumptions, basis for use of bounding analyses, and results.
- When using this option, cracks can be detected in gas-filled systems by methods such as, but not limited to (1) for diesel exhaust piping, detecting staining on external surfaces of components; (2) for accumulators and piping connecting the accumulators to components, monitoring and trending accumulator pressures or refill frequency; and (3) soap bubble testing when systems are pressurized. The SLRA includes the specific methods used.

Surface examinations or VT-1 examinations are conducted on 20 percent of the surface area unless the component is measured in linear feet, as is piping. Alternatively, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. Samples are taken from multiple locations to ensure that a representative sample is examined, focusing on the components most susceptible to the applicable aging effect. The provisions of GALL-SLR Report AMP XI.M38 to conduct inspections in a more severe environment and combination of air environments may be incorporated for these inspections.

In some instances, thermal insulation (e.g., calcium silicate) has been included in-scope to reduce heat transfer from components because absent the insulation, the thermal effects could affect a function described in Title 10 of the *Code of Federal Regulations* (10 CFR) 54.4(a). When metallic jacketing has been used, it is acceptable to conduct external visual inspections of the jacketing to detect damage to the jacketing that would permit in-leakage of moisture as long as the jacketing has been installed in accordance with plant-specific procedures that include configuration features such as minimum overlap, location of seams, etc. If plant-specific procedures do not include these features, an alternative inspection methodology should be proposed.

Component surfaces that are insulated and exposed to condensation (because the in-scope component is operated below the dew point) and insulated outdoor components (aging effects associated with corrosion under insulation for outdoor tanks may be managed by this AMP or GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") are periodically inspected every 10 years during the subsequent period of extended operation. For all outdoor components and any indoor components exposed to condensation (because the in-scope component is operated below the dew point), inspections are conducted of each material type (e.g., steel, SS, copper alloy, aluminum) and environment (e.g., air outdoor, air accompanied by leakage) where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air. A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of twenty-five 1-foot axial length sections and components for each material type is inspected. Samples are taken from multiple locations to ensure that a representative sample is examined. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin. Inspections for cracking due to SCC in aluminum components need not be conducted if it has been determined that SCC is not an applicable aging effect, see SRP-SLR Sections 3.2.2.2.8, 3.3.2.2.8, or 3.4.2.2.7. The following are alternatives to removing insulation after the initial inspection:

a. Subsequent inspections may consist of examination of the exterior surface of the insulation with sufficient acuity to detect indications of damage to the jacketing or protective outer layer (if the protective outer layer is waterproof) of the insulation when the results of the initial inspections meet the following criteria:

- No loss of material due to general, pitting, or crevice corrosion beyond that which could have been present during initial construction is observed during the first set of inspections, and

- No evidence of SCC is observed during the first set of inspections.

If (1) the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or jacketing, (2) there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), or (3) the protective outer layer (where jacketing is not installed) is not waterproof, periodic inspections under the insulation should continue as conducted for the initial inspection.

b. Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of corrosion under insulation is low for tightly adhering insulation. Tightly adhering insulation is considered to be a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope piping that has tightly adhering insulation is visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections are not credited toward the inspection quantities for other types of insulation.

Visual inspection will identify indirect indicators of elastomer and flexible polymer hardening or loss of strength, including the presence of surface cracking, crazing, discoloration, and, for elastomers with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. Visual inspections cover 100 percent of accessible component surfaces. Visual inspection will identify direct indicators of loss of material due to wear, including dimension change, scuffing, and, for flexible polymeric materials with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. Manual or physical manipulation can be used to augment visual inspection to confirm the absence of hardening or loss of strength for elastomers and flexible polymeric materials (e.g., heating, ventilation, and air conditioning flexible connectors) where appropriate. The sample size for manipulation is at least 10 percent of available surface area.

5 ***Monitoring and Trending:*** Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. For sampling-based inspections, the results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

6 ***Acceptance Criteria:*** For each component and aging effect combination, the acceptance criteria are defined to ensure that the need for corrective actions will be identified before loss of intended functions occurs. Acceptance criteria are developed from plant-specific design standards and procedural requirements, the current licensing basis (CLB), industry codes or standards (e.g., ASME Code Section III, ANSI/ASME B31.1), and engineering evaluation. Acceptance criteria, which permit degradation, are based on maintaining the intended function(s) under all CLB design loads. The evaluation projects the degree of observed degradation to the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. Where practical, acceptance criteria are quantitative (e.g., minimum wall thickness, percent shrinkage allowed in an elastomeric seal). Where qualitative acceptance criteria are used, the criteria are clear enough to reasonably ensure that a singular decision is derived based on the observed condition of the systems, structures, and components. For example, if cracks are absent in rigid polymers, the flexibility of an elastomeric sealant is sufficient to ensure that it will properly adhere to surfaces. Electric Power Research Institute Technical Report (TR)-1007933, "Aging Assessment Field Guide," and TR-1009743, "Aging Identification and Assessment Checklist," provide general guidance for evaluation of materials and criteria for their acceptance when performing visual/tactile inspections.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may

apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

For the sampling-based inspections to detect cracking in aluminum and stainless steel components, additional inspections are conducted if one of the inspections does not meet the acceptance criteria due to current or projected degradation (i.e., trending), unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement of all components constructed of the same material and exposed to the same environment. The number of increased inspections is determined in accordance with the site’s corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet the acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. The additional inspections are completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted. If subsequent inspections do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections needed. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. At multi-unit sites, the additional inspections include inspections at all of the units that have the same material, environment, and aging effect combination.

If any projected inspection results will not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site’s corrective action program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50 (TN249), Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** External surface inspections conducted through system inspections and walkdowns have been in effect at many utilities since the mid-1990s in support of the Maintenance Rule (10 CFR 50.65) and have proven effective in maintaining the material condition of plant systems. The elements that compose these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 54.4(a), “Scope.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

EPRI. Technical Report 1009743, “Aging Identification and Assessment Checklist.” Palo Alto, California: Electric Power Research Institute. August 2004.

_____. Technical Report 1007933, “Aging Assessment Field Guide.” Palo Alto, California: Electric Power Research Institute. December 2003.

INPO. Good Practice TS-413, “Use of System Engineers.” INPO 85-033. Washington, DC: Institute of Nuclear Power Operations. May 1988.

XI.M37 FLUX THIMBLE TUBE INSPECTION

Program Description

The Flux Thimble Tube Inspection program is a condition monitoring program used to inspect the thinning of the flux thimble tube wall, which provides a path for the incore neutron flux monitoring system detectors and forms part of the reactor coolant system (RCS) pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. A periodic nondestructive examination methodology, such as eddy current testing (ECT) or another applicant-justified and the U.S. Nuclear Regulatory Commission (NRC)-accepted inspection method, is used to monitor the wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88-09, as described below.

Evaluation and Technical Basis

1 ***Scope of Program:*** The flux thimble tube inspection encompasses all of the flux thimble tubes that form part of the RCS pressure boundary. The instrument guide tubes are not in the scope of this program. Within scope are the licensee responses to NRC Bulletin 88-09, as accepted by the staff in its closure letters about the bulletin, and any amendments to the licensee responses as approved by the staff.

2 ***Preventive Actions:*** The program consists of inspection and evaluation and provides no guidance about preventive actions.

3 ***Parameters Monitored or Inspected:*** Flux thimble tube wall thickness is monitored to detect loss of material from the flux thimble tubes during the subsequent period of extended operation.

4 ***Detection of Aging Effects:*** An inspection methodology (such as ECT) that has been demonstrated to be capable of adequately detecting the wear of the flux thimble tubes is used to detect loss of material during the subsequent period of extended operation. Justification for methods other than ECT should be provided unless use of the alternative method has been previously accepted by the NRC.

Examination frequency is based upon actual plant-specific wear data and wear predictions that have been technically justified as providing conservative estimates of flux thimble tube wear. The interval between inspections is established such that no flux thimble tube is predicted to incur wear that exceeds the established acceptance criteria before the next inspection occurs. The examination frequency may be adjusted based on plant-specific wear projections. Rebaselining of the examination frequency should be justified using plant-specific wear-rate data unless prior plant-specific NRC acceptance for the rebaselining is received outside the license renewal process. If design changes are made to use more wear-resistant thimble tube materials (e.g., chrome-plated stainless steel [SS]), sufficient inspections are conducted at an adequate inspection frequency, as described above, for the new materials.

5 ***Monitoring and Trending:*** Flux thimble tube wall thickness measurements are trended and wear rates are calculated based on plant-specific data using a methodology that includes sufficient conservatism to ensure that wall thickness acceptance criteria continue to be met during plant operation between scheduled inspections. Corrective actions are taken when trending results project that the acceptance criteria would not be met prior to the next planned inspection or the end of the subsequent period of extended operation.

6 ***Acceptance Criteria:*** Appropriate acceptance criteria, such as percent through-wall wear, are established, and inspection results are evaluated and compared with the acceptance criteria. The acceptance criteria are technically justified to provide an adequate margin of safety to ensure that the integrity of the reactor coolant system pressure boundary is maintained. The acceptance criteria include allowances for factors such as instrument uncertainty, uncertainties in wear scar geometry, and other potential inaccuracies, as applicable, to the inspection methodology chosen for use in the program. Acceptance criteria different from those previously documented in the applicant's response to NRC Bulletin 88-09 and amendments thereto, as accepted by the NRC, should be justified.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B (TN249). Appendix A of the Generic Aging Lessons Learned for Subsequent Licensing Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Flux thimble tubes with wall thicknesses that do not meet the established acceptance criteria are isolated, capped, plugged, withdrawn, replaced, or otherwise removed from service in a manner that ensures the integrity of the reactor coolant system pressure boundary is maintained. Analyses may allow repositioning of flux thimble tubes that are approaching the acceptance criteria limit. Repositioning of a tube exposes a different portion of the tube to the discontinuity that is causing the wear.

Flux thimble tubes that cannot be inspected over the tube length, that are subject to wear due to restriction or other defects, and that cannot be shown by analysis to be satisfactory for continued service are removed from service to ensure the integrity of the reactor coolant system pressure boundary.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** In NRC Bulletin 88-09, the NRC requested that licensees implement a flux thimble tube inspection program due to several instances of leaks and due to licensees identifying wear. Utilities established inspection programs in accordance with NRC Bulletin 88-09, which have shown excellent results in identifying and managing the wear of flux thimble tubes. However, leakage events due to accelerated wear have occurred (see NRC Event Notification Report 42822, dated August 31, 2006).

As discussed in NRC Bulletin 88-09, the amount of vibration the thimble tubes experience is determined by many plant-specific factors. Therefore, the only effective method of determining thimble tube integrity is to conduct inspections, which are adjusted to account for plant-specific wear patterns and history.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

NRC. Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1988.

_____. Information Notice No. 87-44, “Thimble Tube Thinning in Westinghouse Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. September 1987.

_____. Information Notice No. 87-44, “Thimble Tube Thinning in Westinghouse Reactors.” Supplement 1. Washington, DC: U.S. Nuclear Regulatory Commission. March 1988.

_____. Licensee Event Notification [EN] 42822, “Technical Specification Required Shutdown Due to Unidentified Reactor Coolant System Leak.” Washington, DC: U.S. Nuclear Regulatory Commission. August 2006.

XI.M38 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

Program Description

This program consists of inspections of the internal surfaces of piping, piping components, ducting, heat exchanger components, and other components exposed to potentially aggressive environments. These environments include air, air with borated water leakage, condensation, gas, diesel exhaust, fuel oil, lubricating oil, and any water-filled systems. Aging effects associated with components (except for elastomers and flexible polymeric components) within the scope of Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report, aging management program (AMP) XI.M20, “Open-cycle Cooling Water System,” AMP XI.M21A, Closed Treated Water Systems,” AMP XI.M27, “Fire Water System,” and AMP XI.M43, “High Density Polyethylene (HDPE) and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping,” are not managed by this program. Aging effects associated with elastomers and flexible polymeric components installed in open-cycle cooling water, closed-cycle cooling water, ultimate heat sink, and fire water systems are managed by this program in lieu of GALL-SLR Report AMP XI.M20, AMP XI.M21A, and AMP XI.M27. In addition, aging effects associated with fire water system components that only have a leakage boundary (spatial) or structural integrity (attached)-intended function may be managed by this program.

These internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. The program includes visual inspections and when appropriate, surface examinations. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this program. This program may also be used to manage cracking due to stress corrosion cracking (SCC) in aluminum and stainless steel (SS) components exposed to aqueous solutions and air environments containing halides. If visual inspection of internal surfaces is not possible, then the applicant needs to provide a plant-specific program.

This program, as written, is not intended for use on components in which recurring internal corrosion is evident based on a search of plant-specific operating experience (OE) conducted during the subsequent license renewal application (SLRA) development. If OE indicates that there has been recurring internal corrosion, a plant-specific program will be necessary unless this program, or another new or existing program, includes augmented requirements that address recurring aging effects (e.g., Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants [SRP-SLR] Sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6). After a failure due to recurring internal corrosion, this program may be used if the failed material is replaced by one that is more corrosion-resistant in the environment of interest, or corrective actions have been taken to prevent the recurrence of the recurring internal corrosion.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program includes the internal surfaces of piping, piping components, ducting, heat exchanger components, and other components. Inspections are performed when the internal surfaces are accessible during the performance of periodic surveillances or during maintenance activities or scheduled outages. This program is not

intended for components for which the loss of intended function has occurred due to age-related degradation.

For situations in which the material and environment combinations are similar for the internal and external surfaces such that the external surface condition is representative of the internal surface condition, external inspections of components may be credited for managing (1) loss of material and cracking of internal surfaces of metallic and cementitious components, (2) loss of material and cracking of internal surfaces for polymeric components, and (3) hardening or loss of strength for the internal surfaces of elastomeric materials. When credited, the program describes the component's internal environment and the credited external component's environment inspected and provides the basis for justifying that the external and internal surface condition and environment are sufficiently similar.

2 ***Preventive Actions:*** This program is a condition monitoring program to detect signs of degradation and does not provide guidance for prevention.

3 ***Parameters Monitored or Inspected:*** This program manages the loss of material, cracking, reduction of heat transfer due to fouling, hardening or loss of strength of elastomeric components, and flow blockage. It monitors surface conditions or wall thickness to identify the loss of material due to corrosion mechanisms for metals and the loss of material due to wear for elastomers and polymers. This program also monitors for changes in the visual appearance of elastomers and polymers and in the suppleness to identify changes in hardening or loss of strength of elastomers and flexible polymers.

Periodic surface examinations are conducted if this program is being used to manage cracking in SS or aluminum components. Visual inspections for leakage or surface cracks are an acceptable alternative to conducting surface examinations to detect cracking if it has been determined that cracks will be detected prior to challenging the structural integrity or intended function of the component.

Examples of indicators of aging effects for metallic components include the following:

- corrosion and surface imperfections
- loss of wall thickness
- flaking of oxide-coated surfaces
- debris accumulation on heat exchanger tube surfaces
- leakage for detection of cracks on the surfaces of SS and aluminum components exposed to air and aqueous solutions containing halides
- accumulation of particulate fouling, biofouling, or macro fouling.

Examples of indicators of the loss of material and changes in the material properties of elastomeric and polymeric materials include the following:

- surface cracking, crazing, scuffing, loss of sealing, and dimensional change (e.g., “ballooning” and “necking”)
- loss of wall thickness
- discoloration (evidence of a potential change in material properties that could be indicative of polymeric degradation)
- exposure of internal reinforcement for reinforced elastomers

- hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate for manipulation.

Examples of inspection parameters for cementitious materials include

- spalling
- scaling
- cracking.

4 ***Detection of Aging Effects:*** Visual and mechanical (e.g., involving manipulation or pressurization of elastomers and flexible polymeric components) inspections conducted under this program are opportunistic in nature; they are conducted whenever piping, heat exchangers, or ducting are opened for any reason. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20 percent of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 25 components per population is inspected at each unit. Otherwise, a technical justification of the methodology and sample size used for selecting components for inspection is included as part of the program's documentation. For multi-unit sites where the sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections at the site as follows. For two-unit sites, 19 components are inspected per unit and for a three-unit site, 17 components are inspected per unit. To conduct 17 or 19 inspections at a unit in lieu of 25, the applicant states in the SLRA the basis for why the operating conditions at each unit are similar enough (e.g., flowrate, chemistry, temperature, excursions) to provide representative inspection results. The basis should include consideration of potential differences such as the following:

- Have power uprates been performed and if so, could more aging have occurred on one unit that has been in the uprate period for a longer time period?
- Have any systems had an out-of-spec water chemistry condition for a longer period of time or out-of-spec conditions that occurred more frequently?
- For raw water systems, is the water source from different sources where one or the other is more susceptible to microbiologically influenced corrosion or other aging effects?
- For components exposed to diesel exhaust, have certain diesels been operating more frequently and have they thus been exposed to more cool-down transients such that more deleterious materials could accumulate?

Where practical, the inspection includes a representative sample of the system population and focuses on the bounding or lead components that are most susceptible to aging because of time in service and the severity of operating conditions. This minimum sample size does not override the opportunistic inspection basis of this AMP. Opportunistic inspections continue even though in a given 10-year period, 20 percent or 25 components might have already been inspected. An inspection of a component in a more severe environment may be credited as being an inspection for the specified environment and for the same material and aging effects in a less severe environment (e.g., a condensation environment is more severe than an indoor controlled air environment because the moisture in the former environment is more likely to result in the loss of material than would be expected from the normally dry surfaces associated with the latter environment). Alternatively, similar environments (e.g., internal uncontrolled indoor, controlled indoor, dry air environments) can be combined into a larger population if the inspections occur on components located in the most severe environment.

Internal visual inspections used to assess the loss of material are capable of detecting surface irregularities that could be indicative of an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected for steel components exposed to raw water, raw water (potable), or wastewater, follow-up volumetric examinations are performed.

Periodic visual inspections or surface examinations are conducted on SS and aluminum to manage cracking every 10 years during the subsequent period of extended operation when applicable (e.g., see SRP-SLR Sections 3.2.2.2.4 and 3.2.2.2.8). One or more of the following three options may be used to implement the periodic visual inspections or surface examinations:

- Surface examination conducted in accordance with plant-specific procedures.
- ASME Code Section XI VT-1 inspections (including those inspections conducted on non-ASME Code components).
- Visual inspections are conducted where it has been analytically demonstrated that surface cracks can be detected by leakage prior to a crack challenging the structural integrity or intended function of the component. The SLRA includes an overview of the analytical method, input variables, assumptions, basis for use of bounding analyses, and results.
- When using this option, cracks can be detected in gas-filled systems by methods such as, but not limited to (1) for diesel exhaust piping, detecting staining on external surfaces of components; (2) for accumulators and piping connecting the accumulators to components, monitoring and trending accumulator pressures or refill frequency; and (3) soap bubble testing when systems are pressurized. The SLRA includes the specific methods used.

Surface examinations or VT-1 examinations are conducted on 20 percent of the surface area inspected unless the component is measured in linear feet, such as piping. Alternatively, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. Samples are taken from multiple locations to ensure that a representative sample is examined, focusing on components most susceptible to the applicable aging effect. Opportunistic inspections need not be conducted once the minimum sample inspections are completed.

To determine the condition of the internal surfaces of buried and underground components, inspections of the interior surfaces of accessible (i.e., above ground) components may be credited if the accessible and the buried or the underground component material, environment, and aging effects are similar.

Visual inspections include all accessible surfaces. Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Unless otherwise required (e.g., by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code [ASME Code]), inspections follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The inspection procedures must be capable of detecting the aging effect(s) under consideration. These inspections provide for the detection of aging effects before the loss of component function.

Visual inspection of flexible polymeric components is performed whenever the component surface is accessible. Visual inspection can provide indirect indicators of the presence of surface cracking, crazing, and discoloration. For elastomers with internal reinforcement, visual inspection can detect the exposure of reinforcing fibers, mesh, or underlying metal. Visual and tactile inspections are performed when the internal surfaces become accessible during the performance of periodic surveillances or during maintenance activities or scheduled outages. Visual inspection provides direct indicators of loss of material due to wear, including dimensional change, scuffing, and the exposure of reinforcing fibers, mesh, or underlying metal for flexible polymeric materials that have internal reinforcement.

Manual or physical manipulation or pressurization of flexible polymeric components is used to augment visual inspection, where appropriate, to assess the loss of material or strength. The sample size for manipulation is at least 10 percent of the accessible surface area, including visually identified suspect areas. For flexible polymeric materials, hardening, loss of strength, or loss of material due to wear is expected to be detectable before any loss of intended function.

5 ***Monitoring and Trending:*** Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

6 ***Acceptance Criteria:*** For each component and aging effect combination, the acceptance criteria are defined to ensure that the need for corrective actions is identified before the loss of intended functions. Acceptance criteria are developed from plant-specific design standards and procedural requirements, the current licensing basis (CLB), industry codes or standards (e.g., ASME Code Section III, ANSI/ASME B31.1), and engineering evaluation. Acceptance criteria, which permit degradation, are based on maintaining the intended function(s) under all CLB design loads. The evaluation projects the degree of observed degradation to the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. Where practical, acceptance criteria are quantitative (e.g., minimum wall thickness, percent shrinkage allowed in an elastomeric seal). Where qualitative acceptance criteria are used, the criteria are clear enough to reasonably ensure that a singular decision is derived based on the observed condition of the systems, structures, and components (SSC). For example, if cracks are absent in rigid polymers, the flexibility of an elastomeric sealant is sufficient to ensure that it will properly adhere to surfaces.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B (TN249). Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Additional inspections are conducted if one of the inspections (i.e., opportunistic, minimum sample size for a 10-year interval) does not meet the acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement of all components constructed of the same material and exposed to the same environment. The number of increased inspections is determined in accordance with the site's corrective action process;

however, there are no fewer than five additional inspections for each inspection that did not meet the acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, in all cases, the additional inspections are completed within the interval in which the original inspection was conducted or, if identified during the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted during the next inspection interval cannot also be credited toward the number of inspections in the latter interval. If subsequent inspections do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections needed. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. At multi-unit sites, the additional inspections include inspections at all of the units that have the same material, environment, and aging effect combination. If any projected inspection results will not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's corrective action program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Inspections of internal surfaces during the performance of periodic surveillance and maintenance activities have been in effect at many utilities in support of plant component reliability programs. These activities have proven effective in maintaining the material condition of plant SSC. The elements that compose these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and staff expectations. The applicant evaluates recent OE and provides objective evidence to support the conclusion that the effects of aging are adequately managed.

The review of plant-specific OE during the development of this program is to be broad and detailed enough to detect instances of aging effects that have occurred repeatedly. In some instances, repeatedly occurring aging effects (i.e., recurring internal corrosion) might result in augmented aging management activities. Further evaluation aging management review line items in SRP-SLR Sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6, "Loss of Material due to Recurring Internal Corrosion," include criteria for determining whether recurring internal corrosion is occurring and recommendations related to augmenting aging management activities.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

EPRI. Technical Report 1007933, “Aging Assessment Field Guide.” Palo Alto, California: Electric Power Research Institute. December 2003.

_____. Technical Report 1009743, “Aging Identification and Assessment Checklist.” Palo Alto, California: Electric Power Research Institute. August 2004.

INPO. Good Practice TS-413, “Use of System Engineers.” INPO 85-033. Atlanta, Georgia: Institute of Nuclear Power Operations. May 1988.

XI.M39 LUBRICATING OIL ANALYSIS

Program Description

The purpose of the Lubricating Oil Analysis program is to provide reasonable assurance that the oil environment in the mechanical systems is maintained at the required quality to prevent or mitigate age-related degradation of components within the scope of this program. This program maintains oil system (lubricating and hydraulic) contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. Oil testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also be indicative of inleakage and corrosion product buildup.

Although primarily a sampling program, the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report XI.M39 identifies when the program is to be augmented to manage the effects of aging for subsequent license renewal. Accordingly, in certain cases identified in this GALL-SLR Report, verification of the effectiveness of the Lubricating Oil Analysis program is conducted. For these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system.

Evaluation and Technical Basis

1 ***Scope of Program:*** Components within the scope of the program include piping, piping components; heat exchanger tubes; reactor coolant pump elements; and any other plant components subject to aging management review (AMR) that are exposed to an environment of lubricating oil (including nonwater-based hydraulic oils).

2 ***Preventive Actions:*** The Lubricating Oil Analysis program maintains oil system contaminants (primarily water and particulates) within acceptable limits.

3 ***Parameters Monitored or Inspected:*** This program performs a check for water and a particle count to detect evidence of contamination by moisture or excessive corrosion.

4 ***Detection of Aging Effects:*** Moisture or corrosion products increase the potential for, or may be indicative of, loss of material due to corrosion and reduction of heat transfer due to fouling. The program performs periodic sampling and testing of lubricating oil for moisture and corrosion particles in accordance with industry standards. The program recommends sampling and testing of the old oil following periodic oil changes or on a schedule consistent with the equipment manufacturer's recommendations or industry standards (e.g., American Society of Testing Materials [ASTM] D 6224-02). Plant-specific operating experience (OE) also may be used to adjust manufacturer's recommendations or industry standards when determining the schedule for periodic sampling and testing when justified by prior sampling results. For hydraulic fluids, if the fluid is replaced based on a periodicity recommended by the fluid manufacturer, equipment vendor, or plant-specific documents, testing need not be conducted for inservice oils. Alternatively, the hydraulic fluid is tested for water content if the oil is not clear or bright, and for particulate count.

In certain cases, as identified by the AMR items in this GALL-SLR Report, inspection of selected components is to be undertaken to verify the effectiveness of the program such that significant degradation is not occurring and that the component's intended function is maintained during the subsequent period of extended operation.

5 ***Monitoring and Trending:*** Oil analysis results are reviewed to determine whether alert levels or limits have been reached or exceeded. This review also checks for unusual trends.

6 ***Acceptance Criteria:*** Water and particle concentration should not exceed limits based on equipment manufacturer's recommendations or industry standards. Phase-separated water in any amount is not acceptable.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B (TN249). Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Corrective actions may include increased monitoring, corrective maintenance, further laboratory analysis, and engineering evaluation of the system. If a limit is reached or exceeded, actions to address the condition are taken.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The OE at some plants has identified (1) water in the lubricating oil and (2) particulate contamination. However, no instances of component failures attributed to lubricating oil contamination have been identified.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

ASTM. ASTM D 6224-02, "Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment." West Conshohocken, Pennsylvania: American Society of Testing Materials. 2002.

XI.M40 MONITORING OF NEUTRON-ABSORBING MATERIALS OTHER THAN BORAFLEX

Program Description

Many neutron-absorbing materials are used in spent fuel pools. This aging management program (AMP) addresses aging management of spent fuel pools that use materials other than Boraflex, such as Boral, Metamic, boron steel, and Carborundum. Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M22, "Boraflex Monitoring," addresses aging management of spent fuel pools that use Boraflex as the neutron-absorbing material. When a spent fuel pool criticality analysis credits both Boraflex and materials other than Boraflex, the guidance in both AMPs XI.M22 and XI.M40 applies.

A monitoring program is implemented to assure that degradation of the neutron-absorbing material used in spent fuel pools that could compromise the criticality analysis will be detected. The AMP relies on periodic inspection, testing, monitoring, and analysis of the criticality design to assure that the required 5 percent subcriticality margin is maintained during the period of subsequent license renewal.

Evaluation and Technical Basis

1 ***Scope of Program:*** The AMP manages the effects of aging on neutron-absorbing components/materials other than Boraflex used in spent fuel racks.

2 ***Preventive Actions:*** This AMP is a condition monitoring program. Therefore, there are no preventative actions.

3 ***Parameters Monitored or Inspected:*** For these materials, gamma irradiation and/or long-term exposure to the wet pool environment may cause loss of material and changes in dimension (such as gap formation, formation of blisters, pits and bulges) that could result in loss of the neutron-absorbing capability of the material. The parameters monitored include the physical condition of the neutron-absorbing materials, such as *in-situ* gap formation, geometric changes in the material (formation of blisters, pits, and bulges) as observed from coupons or *in situ*, and decreased boron-10 areal density, etc. The parameters monitored are directly related to determination of the loss of material or loss of the neutron absorption capability of the material(s).

4 ***Detection of Aging Effects:*** The loss of material and the degradation of neutron-absorbing material capacity are determined through coupon and/or direct *in-situ* testing. Such testing should include periodic verification of boron loss through boron-10 areal density measurement of coupons or through direct *in-situ* techniques. In addition to measuring boron content, testing should also be capable of identifying indications of geometric changes in the material (blistering, pitting, and bulging). The frequency of the inspection and testing depends on the condition of the neutron-absorbing material and is determined and justified based on the plant-specific operating experience (OE) of the licensee. The maximum interval between inspections for polymer-based materials (e.g., Carborundum, Tetrabor), regardless of OE, should not exceed 5 years. The maximum interval between inspections for nonpolymer-based materials (e.g., Boral, Metamic, Boralcan, borated stainless steel), regardless of OE, should not exceed 10 years.

5 ***Monitoring and Trending:*** The measurements from periodic inspections and analysis are compared to baseline information or prior measurements and analysis for trend analysis. The approach for relating the measurements to the performance of the spent fuel neutron-

absorber materials is specified by the applicant, considering differences in exposure conditions, vented/nonvented test samples, and spent fuel racks, etc.

6 ***Acceptance Criteria:*** Although the goal is to ensure maintenance of the 5 percent subcriticality margin for the spent fuel pool, the specific acceptance criteria for the measurements and analyses are specified by the applicant.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B (TN249). Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Corrective actions are initiated if the results from measurements and analysis indicate that the 5 percent subcriticality margin cannot be maintained because of current or projected future degradation of the neutron-absorbing material. Corrective actions may consist of providing additional neutron-absorbing capacity with an alternate material or applying other options that are available to maintain the subcriticality margin.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Applicants for license renewal reference plant-specific OE and industry experience to provide reasonable assurance that the program is able to detect degradation of the neutron-absorbing material in the applicant's spent fuel pool. Some of the industry OE that should be included is discussed in Information Notice 2009-26, "Degradation of Neutron-Absorbing Materials in the Spent Fuel Pool," and is listed below:

a. Loss of material from the neutron-absorbing material has been seen at many plants, including loss of aluminum, which was detected by monitoring the aluminum concentration in the spent fuel pool. One instance of this was documented in the Vogtle license renewal application Water Chemistry program B.3.28.

b. Blistering has also been noted at many plants. Examples include blistering at Seabrook and Beaver Valley.

c. The significant loss of neutron-absorbing capacity of the plate-type Carborundum material has been reported at Palisades.

d. The coupon testing program at Kewaunee has observed loss of the boron-10 areal density of Tetrabor.

e. The coupon testing programs at Calvert Cliffs Unit 1 and Crystal River Unit 3 have observed weight loss in sheet-type Carborundum.

f. The applicant should describe how the monitoring program described above is capable of detecting the aforementioned degradation mechanisms.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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XI.M41 BURIED AND UNDERGROUND PIPING AND TANKS

Program Description

This aging management program (AMP) manages the aging of the external surfaces of buried and underground piping and tanks. It addresses piping and tanks composed of any material, including metallic, polymeric, and cementitious materials. The program manages aging through preventive, mitigative, inspection, and in some cases, performance monitoring activities. It manages applicable aging effects such as loss of material and cracking.

Depending on the material, preventive and mitigative techniques may include external coatings, cathodic protection, and the quality of backfill. Also, depending on the material, inspection activities may include electrochemical verification of the effectiveness of cathodic protection, nondestructive evaluation of pipe or tank wall thicknesses, pressure testing of the pipe, performance monitoring of fire mains, and visual inspections of the pipe or tank from the exterior.

This program does not provide aging management of selective leaching. The Selective Leaching program of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M33 is applied in addition to this program for applicable materials and environments. In addition, this program does not provide aging management of buried and underground piping constructed of high-density polyethylene or repaired with carbon fiber reinforced polymer. AMP XI.M43, "High Density Polyethylene (HDPE) and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping," is applied instead of this program.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages the effects of aging of the external surfaces of buried and underground piping and tanks constructed of any material including metallic, polymeric, and cementitious materials. The term "polymeric" material refers to plastics or other polymers that compose the pressure boundary of the component. The program addresses aging effects such as loss of material and cracking. The program also manages the loss of material due to the corrosion of piping system bolting within the scope of this program. The Bolting Integrity program (GALL-SLR Report AMP XI.M18) manages other aging effects associated with piping system bolting. This program does not provide aging management of selective leaching. The Selective Leaching of Materials program (GALL-SLR Report AMP XI.M33) is applied in addition to this program for applicable materials and environments.

2 ***Preventive Actions:*** Preventive actions used by this program vary with the material of the tank or pipe and the environment (e.g., air, soil, concrete) to which it is exposed. There are no recommended preventive actions for titanium alloy, super austenitic stainless steels, and nickel alloy materials. Preventive actions for buried and underground piping and tanks are conducted in accordance with Table XI.M41-1 and as described below.

Table XI.M41-1. Preventive Actions for Buried and Underground Piping and Tanks

Material	Buried	Underground
Stainless steel	C, B	None
Steel	C, CP, B	C
Copper alloy	C, CP, B	C

Material	Buried	Underground
Aluminum alloy	C, CP, B	None
Cementitious	C, CP, B	C
Polymer	B	None

C = coatings; CP = cathodic protection; B = backfill.

a. For buried stainless steel or cementitious piping or tanks, coatings are provided based on the environmental conditions (e.g., stainless steel in chloride containing environments). Applicants provide justification when coatings are not provided. Coatings are in accordance with Table 1 of National Association of Corrosion Engineers (NACE) SP0169-2007 or Section 3.4 of NACE RP0285-2002 as well as the following coating types: asphalt/coal tar enamel, concrete, elastomeric polychloroprene, mastic (asphaltic), epoxy polyethylene, polypropylene, polyurethane, and zinc.

b. For buried steel, copper alloy, and aluminum alloy piping and tanks and underground steel and copper alloy piping and tanks, coatings are in accordance with Table 1 of NACE SP0169-2007 or Section 3.4 of NACE RP0285-2002.

c. Cathodic protection is in accordance with NACE SP0169-2007 or NACE RP0285-2002. The system is operated so that the cathodic protection criteria and other considerations described in the standards are met at every location in the system for which cathodic protection is credited. System monitoring is conducted annually with a grace period of 1 to 2 months; however, in each calendar year, system monitoring is conducted at least once. The equipment used to implement cathodic protection need not be qualified in accordance with Title 10 of the Code of Federal Regulations (10 CFR) Part 50, Appendix B.

d. Cathodic protection is supplied for reinforced concrete pipe and prestressed concrete cylinder pipe. Applicants provide justification when cathodic protection is not provided.

e. Critical potentials for cathodic protection:

    i. To prevent damage to the coating or base metal (e.g., aluminum), the limiting critical potential should not be more negative than −1,200 mV.

    ii. When an impressed current cathodic protection system is used with prestressed concrete cylinder pipe, steps are taken to avoid an excessive level of potential that could damage the prestressing wire. Therefore, polarized potentials more negative than -1,000 mV relative to a copper/copper sulfate reference electrode (CSE) are avoided to prevent hydrogen generation and possible hydrogen embrittlement of the high-strength prestressing wire.

    iii. Depending on the environment, steel (in a carbonate-bicarbonate environment) and stainless steel components can experience stress corrosion cracking depending on the cathodic protection polarization level, temperature, pH, etc. If these conditions are applicable, the applicant describes the conditions and alternative cathodic protection levels in the subsequent license renewal application (SLRA).

    iv. Any further over-protection limits are defined by the applicant and managed during surveillance activities. The use of excessive polarized potentials on externally coated pipelines should be avoided.

f. Backfill is consistent with NACE SP0169-2007 Section 5.2.3 or NACE RP0285-2002, Section 3.6. The staff considers backfill that is located within 6 inches of the component that meets ASTM D 448-08 size number 67 (size number 10 for polymeric materials) to meet the objectives of NACE SP0169-2007 and NACE RP0285-2002. For stainless steel and cementitious materials, backfill limits apply only if the component is coated. For materials other than aluminum alloy, the staff also considers the use of controlled low-strength materials (flowable backfill) acceptable to meet the objectives of NACE SP0169-2007.

g. Alternatives to the preventive actions in Table XI.M41-1 are as follows:

   i. A broader range of coatings may be used if justification is provided in the SLRA.

   ii. Backfill quality may be demonstrated by plant records or by examining the backfill while conducting the inspections described in the “detection of aging effects” program element of this AMP.

   iii. For fire mains installed in accordance with National Fire Protection Association (NFPA) 24, preventive actions beyond those in NFPA 24 need not be provided if (1) the system undergoes either a periodic flow test in accordance with NFPA 25; (2) the activity of the jockey pump (e.g., number of pump starts, run time) is monitored as described in “detection of aging effects” program element of this AMP; or (3) an annual system leakage rate test is conducted.

   iv. Failure to provide cathodic protection in accordance with Table XI.M41-1 may be acceptable if it is justified in the SLRA. The justification addresses soil sample locations, soil sample results, the methodology and results of how the overall soil corrosivity was determined, pipe to soil potential measurements and other relevant parameters.

If cathodic protection is not provided for any reason, the applicant reviews the most recent 10 years of plant-specific operating experience (OE) to determine whether degraded conditions that would not have met the acceptance criteria of this AMP have occurred. This search includes components that are not in-scope for license renewal if, when compared to in-scope piping, they are of similar materials and coating systems and are buried in a similar soil environment. The results of this expanded plant-specific OE search are included in the SLRA.

3 *Parameters Monitored or Inspected:*

a. Visual inspections of (1) the external surface condition of buried or underground piping or tanks; (2) the external surface condition of associated coatings; or (3) external surfaces of controlled low-strength material backfill are performed. Monitoring of the surface condition of the component is conducted to detect indications of aging effects described in Section 3.b (below). Monitoring of the surface condition of coatings is conducted to determine whether the coatings are intact, well-adhered, and otherwise sound—such that aging effects would not be expected for the base material of the component. Monitoring of the external surfaces of controlled low-strength material backfill is conducted to detect potential cracks that could admit groundwater to the surface of the component.

b. Visual inspections of the external surface condition of the component should detect:

   i. loss of material due to general, pitting, crevice corrosion, and microbiologically influenced corrosion (MIC) for copper alloy and steel components;

   ii. loss of material due to pitting and crevice corrosion for aluminum alloy and titanium alloy components;

iii. loss of material due to pitting and crevice corrosion, and MIC for stainless steel, super austenitic, and nickel alloy components;

iv. loss of material due to wear for polymeric materials;

v. cracking due to chemical reaction, weathering, or settling for cementitious materials;

vi. cracking or blistering due to water absorption for high-density polyethylene and fiberglass components;

vii. cracking due to corrosion of reinforcement for reinforced concrete pipe; and

viii. loss of material due to delamination, exfoliation, spalling, popout, or scaling for cementitious materials.

c. Volumetric nondestructive examination techniques as well as pit depth gages or calipers may be used for measuring wall thickness as long as (1) they have been determined to be effective for the material, environment, and conditions (e.g., remote methods) during the examination; and (2) they are capable of quantifying general wall thickness and the depth of pits. Wall thickness measurements are conducted to detect potential loss of material.

d. Inspections for cracking due to stress corrosion cracking for steel (in a carbonate-bicarbonate environment), stainless steel, and susceptible aluminum alloy materials use a method that has been determined to be capable of detecting cracking. Coatings that (1) are intact, well-adhered, and otherwise sound for the remaining inspection interval; and (2) exhibit small blisters that are few in number and completely surrounded by sound coating bonded to the substrate do not have to be removed. Inspections for cracking are conducted to assess the impact of cracks on the pressure boundary function of the component.

e. Pipe-to-soil potential and the cathodic protection current are monitored for steel, copper alloy, and aluminum alloy piping and tanks in contact with soil to determine the effectiveness of cathodic protection systems.

f. When using alternatives to excavated direct visual examination of fire mains, appropriate inspection parameters are used to detect indications of fire main leakage. For example:

i. during periodic flow test, a reduction in available flow rate;

ii. for jockey pump monitoring, an increase in the number of pump starts or run time of the pump;

iii. during annual system leakage rate testing an increase in unaccounted flow leak rates (i.e., the leakage path could be through a valve disc and seat, which is not pertinent to this AMP).

4 ***Detection of Aging Effects:*** Methods and frequencies used for the detection of aging effects vary with the material and environment of the buried and underground piping and tanks. Inspections of buried and underground piping and tanks are conducted in accordance with Table XI.M41-2 and as described below. There are no inspection recommendations for titanium alloy, super austenitic, or nickel alloy materials, but these materials are opportunistically inspected when exposed. Table XI.M41-2 inspection quantities are for a single-unit plant. For two-unit sites, the inspection quantities (i.e., not the percentage of pipe length) are increased by 50 percent. For a three-unit site, the inspection quantities are doubled. For multi-unit sites, the inspections are distributed evenly among the units. Additional inspections, beyond those listed in Table XI.M41-2 may be appropriate if exceptions are taken to program element 2, “preventive actions,” or in response to plant-specific OE. Plant-specific OE includes components outside of the scope of SLR if they are representative of in-scope components (e.g., similar material composition, degradation mechanisms, coatings, soil conditions, history of cathodic protection).

Inspections of buried and underground piping and tanks are conducted during each 10-year period, commencing 10 years prior to the subsequent period of extended operation. Piping inspections are typically conducted by visual examination of the external surfaces of pipe or coatings. Tank inspections are conducted externally by visual examination of the surfaces of the tank or coating or internally by volumetric methods. Opportunistic inspections are conducted for in-scope piping whenever they become accessible. Visual inspections are supplemented with surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed.

Table XI.M41-2. Inspection of Buried and Underground Piping and Tanks

Inspections of Buried Piping		
Material	**Preventive Action Categories**	**Inspection See Section 4.c. for Extent of Inspections**
Stainless steel		1 inspection
Polymeric	Backfill is in accordance with preventive actions program element	1 inspection
	Backfill is not in accordance with preventive actions program element	The smaller of 1% of the length of pipe or 2 inspections
Cementitious		1 inspection
Steel	C	The smaller of 0.5% of the piping length or 1 inspection
	D	The smaller of 1% of the piping length or 2 inspections
	E	The smaller of 5% of the piping length or 3 inspections
	F	The smaller of 10% of the piping length or 6 inspections
Copper alloy	C	The smaller of 0.5% of the piping length or 1 inspection
	D	The smaller of 1% of the piping length or 2 inspections
	E	The smaller of 5% of the piping length or 3 inspections
	F	The smaller of 10% of the piping length or 6 inspections
Aluminum alloy	C	The smaller of 0.5% of the piping length or 1 inspection
	D	The smaller of 1% of the piping length or 2 inspections
	E	The smaller of 5% of the piping length or 3 inspections
	F	The smaller of 10% of the piping length or 6 inspections

Inspections of Buried Piping			
Material	**Preventive Action Categories**		**Inspection See Section 4.c. for Extent of Inspections**
Inspections of Buried Tanks and Underground Piping and Tanks			
Material	**Buried Tanks**	**Underground Piping**	**Underground Tanks**
Stainless steel	All tanks	1 inspection	All tanks
Polymeric	All tanks	1 inspection	None
Cementitious	All tanks	1 inspection	None
Steel	All tanks	The smaller of 2% of the piping length or 2 inspections	All tanks
Copper alloy or Aluminum alloy	All tanks	The smaller of 1% of the length of piping or 1 inspection	All tanks

The Preventive Action Categories are used as follows:

A: Category A no longer used.

B: Category B no longer used.

C: Category C applies when:

- a. Cathodic protection was installed or refurbished 5 years prior to the end of the inspection period of interest.
- b. Cathodic protection has operated at least 85% of the time either since 10 years prior to the subsequent period of extended operation or since installation/refurbishment, whichever is shorter. Time periods during which the cathodic protection system is offline for testing do not have to be included in the total nonoperating hours.
- c. Cathodic protection has provided effective protection for buried piping as evidenced by meeting the acceptance criteria of Table XI.M41-3 of this AMP at least 80% of the time either since 10 years prior to the subsequent period of extended operation or since installation/refurbishment, whichever is shorter. As-found results of annual surveys are to be used to determine locations within the plant's population of buried pipe where cathodic protection acceptance criteria have, or have not, been met.

D: Inspection criteria provided for Category D piping may be used for the portions of in-scope buried piping for which it has been determined, in accordance with the "preventive actions" program element of this AMP, that external corrosion control is not required.

E: Inspection criteria provided for Category E piping may be used for the portions of the population of buried piping where:

- a. An analysis, conducted in accordance with the "preventive actions" program element of this AMP, has determined that installation or operation of a cathodic protection system is impractical; or
- b. A cathodic protection system has been installed but all or portions of the piping covered by that system fail to meet any of the criteria of Category C piping above, provided:
  - i. Coatings and backfill are provided in accordance with the "preventive actions" program element of this AMP;
  - ii. Plant-specific OE is acceptable (i.e., no leaks in buried piping due to external corrosion, no significant coating degradation or metal loss in more than 10% of inspections conducted); and
  - iii. Soil has been determined to not be corrosive for the material type (i.e., nine points or less using American Water Works Association C105, "Polyethylene Encasement for Ductile-Iron Pipe Systems," Table A.1, "Soil Test Evaluation," or 10 points or less using Electric Power Research Institute Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," Table 9-4, "Soil Corrosivity Index from BPWORKS"). In order to determine that the soil is not corrosive, the applicant:
    - (a) Obtains a minimum of three sets of soil samples in each soil environment (e.g., moisture content, soil composition) in the vicinity in which in scope components are buried.
    - (a) Tests the soil for soil resistivity, corrosion-accelerating bacteria, pH, moisture, chlorides, sulfates, and redox potential.
    - (b) Determines the potential soil corrosivity for each material type of buried in scope piping. In addition to evaluating each individual parameter, the overall soil corrosivity is determined.

(c) Conducts soil testing once in each 10-year period starting 10 years prior to the subsequent period of extended operation.

F: Inspection criteria provided for Category F piping is used for the portions of in-scope buried piping for whichthe cathodic protection system is not meeting performance goals defined in Category C and the in scope buried piping cannot be classified as Category D or E. Category F is not intended for instances where cathodic protection is not provided. In this case, the applicant would develop plant-specific inspection quantities.

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a. Transitioning to a Higher Number of Inspections: Plant-specific conditions can result in transitioning to a higher number of inspections than originally planned at the beginning of a 10-year interval. For example, degraded performance of the cathodic protection system could result in transitioning from Preventive Action Category C to Preventive Action Category E. Coating, backfill, or the condition of exposed piping that do not meet the acceptance criteria could result in transitioning from Preventive Action Category E to Preventive Action Category F. If this transition occurs in the latter half of the current 10-year interval, the timing of the additional examinations is based on the severity of the degradation identified and is commensurate with the consequences of a leak or loss of function, but in all cases, the examinations are completed within 4 years after the end of the particular 10-year interval. These additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited toward the number of inspections stated in Table XI.M41-2 for the following 10-year interval.

b. Exceptions to Table XI.M41-2 inspection quantities:

   i. Where piping constructed of steel, copper alloy, or aluminum alloy has been coated with the same coating system and the backfill has the same requirements, the total inspections for this piping may be combined to satisfy the recommended inspection quantity. For example, for Preventive Action Category F, 10 percent of the total of the associated steel, copper alloy, or aluminum alloy is inspected; or six 10-foot segments of steel, copper alloy, or aluminum alloy piping are inspected.

   ii. For buried piping or tanks, inspections may be reduced to one-half the number of inspections indicated in Table XI.M41-2 when performance of the indicated inspections necessitates excavation of pipes or tanks that have been fully backfilled using controlled low-strength material. The inspection quantity is rounded up (e.g., where three inspections are recommended in Table XI.M41-2, two inspections are conducted).

   When conducting inspections of buried components embedded in concrete backfill, the backfill may be excavated and the pipe or tank examined, or the soil around the backfill may be excavated and the cementitious material examined. The inspection includes excavation of the top surfaces and at least 50 percent of the side surface to visually inspect for cracks in the backfill that could admit groundwater to the external surfaces of the component. When conducting inspection of backfill based on the number of inspections designated for that material type, 10 linear feet of the backfill are exposed for each inspection.

   iii. No inspections are necessary if all the pipes or tanks constructed from a specific material type are fully backfilled using controlled low-strength material for: (1) polymeric and cementitious materials; (2) steel and copper alloy materials when Preventive Action Category C is met; and (3) stainless steel materials.

   iv. If all of the in-scope polymeric material is nonsafety-related, no more than one inspection needs to be conducted.

   v. Buried polymeric tanks are only inspected if backfill is not used in accordance with the preventive actions.

   vi. Stainless steel tanks are inspected when they are not coated and the underground environment is potentially exposed to inleakage of groundwater or rainwater.

   vii. Steel, copper alloy, and aluminum alloy buried tanks are not inspected if the cathodic protection provided for the tank met the criteria for Preventive Action Category C.

c. Guidance related to the extent of inspections for piping is as follows:

   i. When the inspections are based on the number of inspections in lieu of the percentage of piping length, 10 feet of piping are exposed for each inspection.

   ii. When the percentage of inspections for a given material type results in an inspection quantity of less than 10 feet, then 10 feet of piping are inspected. If the entire run of piping of that material type is less than 10 feet in total length, then the entire run of piping is inspected.

d. Piping inspection location selection: Piping inspection locations are selected based on risk (i.e., susceptibility to degradation and consequences of failure). Characteristics such as coating type (i.e., material type), coating condition, cathodic protection efficacy, backfill characteristics, soil resistivity, pipe contents, and pipe function are considered. Opportunistic examinations of nonleaking pipes may be credited toward examinations if the location selection criteria are met. The use of guided wave ultrasonic examinations may not be substituted for the inspections listed in the table.

e. Alternatives to visual examination of piping are as follows:

   i. Aging effects associated with fire mains may be managed by either (1) conducting a flow test as described in Section 7.3 of NFPA 25 at a frequency of at least one test in each 1-year period; (2) monitoring the activity of the jockey pump (e.g., pump starts, run time) on an interval not to exceed 1 month; or (3) conducting an annual system leak rate test. If the aging effects are not managed by one of these methods, and the extent of inspections is not based on the percentage of piping for that material type, then two additional inspections are added to the inspection quantity for that material type.

   ii. At least 25 percent of the in-scope piping constructed from the material under consideration is pressure tested on an interval not to exceed 5 years. The piping is pressurized to 110 percent of the design pressure of any component within the boundary (not to exceed the maximum allowable test pressure of any nonisolated components) and the test pressure is held for a continuous 8-hour interval.

   iii. At least 25 percent of the in-scope piping constructed from the material under consideration is internally inspected by a method capable of precisely determining pipe wall thickness. The inspection method has been determined to be capable of detecting both general and pitting corrosion on the external surface of the piping and is qualified by the applicant to identify loss of material that does not meet the acceptance criteria. Ultrasonic examinations, in general, satisfy this criterion. As of the effective date of this document, guided wave ultrasonic examinations do not meet the intent of this paragraph. If internal inspections are to be conducted in lieu of direct visual examination, they are conducted at an interval not to exceed 10 years.

f. Examinations are conducted from the external surface of the tank using visual techniques or from the internal surface of the tank using volumetric techniques. A minimum of 25 percent coverage is obtained. This area includes at least some of both the top and bottom of the tank. If the tank is inspected internally by volumetric methods, the method is capable of determining tank wall thickness, determined to be capable of detecting both general and pitting corrosion, and qualified by the applicant to identify loss of material that does not meet the acceptance criteria. Double-wall tanks may be examined by monitoring the annular space for leakage.

5 ***Monitoring and Trending:*** For piping and tanks protected by cathodic protection systems, potential difference and current measurements are trended to identify changes in the effectiveness of the systems and/or coatings. If aging of fire mains is managed through monitoring jockey pump activity (or a similar parameter), the jockey pump activity (or similar parameter) is trended to identify changes in pump activity that may be the result of increased leakage from buried fire main piping. Likewise, if leak rate testing is conducted, leak rates are trended. Where wall thickness measurements are conducted, the results are trended when follow-up examinations are conducted.

Where practical, all other degradation (e.g., coating condition, cementitious piping degradation) is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

6 ***Acceptance Criteria:*** The acceptance criteria associated with this AMP are as follows:

a. For coated piping or tanks, there is either no evidence of coating degradation, or the type and extent of coating degradation is evaluated as being insignificant by (1) an individual who has a NACE Coating Inspector Program Level 2 or 3 inspector qualification; (2) an individual who has completed the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course; or (3) a coatings specialist qualified in accordance with an ASTM standard endorsed in Regulatory Guide 1.54, Revision 2, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants."

b. Cracking is absent in rigid polymeric components. Blisters, gouges, or wear of nonmetallic piping are evaluated.

c. The measured wall thickness projected to the end of the subsequent period of extended operation meets minimum wall thickness requirements.

d. Indications of cracking in metallic pipe are managed in accordance with the "corrective actions" program element.

e. Cementitious piping may exhibit minor cracking and loss of material if there is no evidence of leakage exposed or rust staining from rebar or reinforcing "hoop" bands.

f. Backfill is acceptable if the inspections do not reveal evidence that the backfill caused damage to the component's coatings or the surface of the component (if not coated).

g. Flow test results for fire mains are in accordance with NFPA 25, Section 7.3.

h. For pressure tests, the test acceptance criteria are that there are no visible indications of leakage, and no drop in pressure within the isolated portion of the piping that is not accounted for by a temperature change in the test media or by quantified leakage across test boundary valves.

i. Changes in jockey pump activity (or similar parameter) that cannot be attributed to causes other than leakage from buried piping are not occurring.

j. When firewater system leak rate testing is conducted, leak rates are within acceptance limits of plant-specific documents.

k. Cracks in cementitious backfill that could admit groundwater to the surface of the component are not acceptable.

l. Criteria for pipe-to-soil potential when using a saturated copper/copper sulfate reference electrode is as stated in Table XI.M41-3, or acceptable alternatives as stated below.

Table XI.M41-3. Cathodic Protection Acceptance Criteria

Material	Criteria[a, b, c]
Steel	−850 mV relative to a copper/copper sulfate reference electrode, instant off
Copper alloy	100 mV minimum polarization
Aluminum alloy	100 mV minimum polarization

(a) Plants with sacrificial anode systems state the test method and acceptance criteria and the basis for the method and criteria in the application.
(b) For steel piping, when (1) active microbiologically influenced corrosion has been identified or is probable; (2) temperatures are greater than 60 °C (140 °F); or (3) in weak acid environments, a polarized potential of -950 mV or more negative is recommended.
(c) The 100 mV polarization criterion is limited to electrically isolated piping sections or areas of grounded piping where the effects of mixed potentials are shown to be minimal. When the 100 mV criterion is used to protect copper alloy or aluminum ally components, applicants must explain in the application why the effects of mixed potentials are minimal and why the most anodic metal in the system is adequately protected.

m. Alternatives to the -850 mV criterion for steel piping in Table XI.M41-3 are as follows:

i. 100 mV minimum polarization

ii. -750 mV relative to a copper/copper sulfate reference electrode (CSE), instant off where soil resistivity is greater than 10,000 ohm-cm to less than 100,000 ohm-cm

iii. -650 mV relative to a CSE, instant off where soil resistivity is greater than 100,000 ohm-cm

iv. Verify there is less than 1 mpy loss of material. Loss of material rates in excess of 1 mpy may be acceptable if an engineering evaluation demonstrates that the corrosion rate would not result in a loss of intended function prior to the end of the subsequent period of extended operation. The engineering evaluation is cited and summarized in the SLRA.

When using the 100 mV, -750 mV, or -650 mV polarization criteria as an alternative to the -850 mV criterion for steel piping, a means of verifying the effectiveness of the protection of the most anodic metal is incorporated into the program. One acceptable means of verifying the effectiveness of the cathodic protection system, or demonstrating that the loss of material rate is acceptable, is to use installed electrical resistance corrosion rate probes. The external loss of material rate is verified as follows:

- Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate.
- Every 2 years when using the 100 mV minimum polarization.
- Every 5 years when using the -750 mV or -650 mV criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.

As an alternative to verifying the effectiveness of the cathodic protection system every 5 years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of 10 annual consecutive soil samples, soil resistivity testing can be extended to every 5 years if the results of the soil sample tests consistently verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, all soil resistivity values were greater than 10,000 ohm-cm).

When electrical resistance corrosion rate probes will be used, the application identifies:

- The qualifications of the individuals that will determine the installation locations of the probes and the methods of use (e.g., NACE CP4, “Cathodic Protection Specialist”).
- How the impact of significant site features (e.g., large cathodic protection current collectors, shielding due to large objects located in the vicinity of the protected piping) and local soil conditions will be factored into placement of the probes and use of probe data.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

a. Where damage to the coating has been evaluated as being significant and the damage was caused by nonconforming backfill, an extent of condition evaluation is conducted to determine the extent of degraded backfill in the vicinity of the observed damage.

b. If coated or uncoated metallic piping or tanks show evidence of corrosion, the remaining wall thickness in the affected area is determined to ensure that the minimum wall thickness is maintained. This may include different values for large area minimum wall thickness and local area wall thickness. If the wall thickness extrapolated to the end of the subsequent period of extended operation meets the minimum wall thickness requirements, the recommendations for expansion of sample size below do not apply.

c. When the coatings, backfill, or condition of exposed piping does not meet the acceptance criteria, the degraded condition is repaired or the affected component is replaced. In addition, when the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the subsequent period of extended operation, an expansion of sample size is conducted. The number of inspections within the affected piping categories is doubled or increased by five, whichever is smaller. If the acceptance criteria are not met in any of the expanded samples, an analysis is conducted to determine the extent of condition and extent of cause. The number of follow-on inspections is determined based on the extent of condition and extent of cause.

d. The timing of the additional examinations is based on the severity of the degradation identified and is commensurate with the consequences of a leak or loss of function. However, in all cases, the expanded sample inspection is completed within the 10-year interval during which the original inspection was conducted or, if identified during the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval. These additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited toward the number of inspections in Table XI.M41-2 for the following 10-year interval. The number of inspections may be limited by the extent of piping or tanks subject to the observed degradation mechanism.

e. The expansion of sample inspections may be halted in a piping system or portion of system that will be replaced within the 10-year interval during which the inspections were conducted or, if identified during the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval.

f. Unacceptable cathodic protection survey results are entered into the plant corrective action program.

g. Sources of leakage detected during pressure tests are identified and corrected.

h. When using the option of monitoring the activity of a jockey pump instead of inspecting buried fire water system piping, a flow test or system leak rate test is conducted by the end of the next refueling outage or as directed by the current licensing basis, whichever is shorter, when unexplained changes in jockey pump activity (or equivalent equipment or parameter) are observed.

i. Indications of cracking are evaluated in accordance with applicable codes and plant-specific design criteria.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B (TN249). Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** OE shows that buried and underground piping and tanks are subject to corrosion. Corrosion of buried oil, gas, and hazardous materials pipelines have been adequately managed through a combination of inspections and mitigative techniques, such as those prescribed in NACE SP0169-2007 and NACE RP0285-2002. Given the differences in piping and tank configurations between transmission pipelines and those in nuclear facilities, it is necessary for the applicant to evaluate both plant-specific and nuclear industry OE and to modify its AMP accordingly. Evaluation of plant-specific OE includes components outside of the scope of SLR if they are representative of in-scope components (e.g., similar material composition, degradation mechanisms, coatings, soil conditions, history of cathodic protection). The following examples of industry experience may be of significance to an applicant’s program:

a. In August 2009, a leak was discovered in a portion of buried aluminum pipe where it passed through a concrete wall. The piping is in the condensate transfer system. The failure was caused by vibration of the pipe within its steel support system. This vibration led to coating failure and eventual galvanic corrosion between the aluminum pipe and the steel supports (Agencywide Documents Access and Management System [ADAMS] Accession No. ML093160004).

b. In June 2009, an active leak was discovered in buried piping associated with the condensate storage tank. The leak was discovered because elevated levels of tritium were detected. The cause of the through-wall leaks was determined to be the degradation of the protective moisture barrier wrap that allowed moisture to come in contact with the piping resulting in external corrosion (ADAMS Accession No. ML093160004).

c. In April 2010, while performing inspections as part of its buried pipe program, a licensee discovered that major portions of the auxiliary feedwater piping were substantially degraded. The licensee's cause determination attributes the cause of the corrosion to the failure to properly coat the piping "as specified" during original construction. The affected piping was replaced during the next refueling outage (ADAMS Accession No. ML103000405).

d. In November 2013, minor weepage was noted in a 10-inch service water supply line to the emergency diesel generators while performing a modification to a main transformer moat. Coating degradation was noted at approximately 10 locations along the exposed piping. The leaking and unacceptable portions of the degraded pipe were clamped and recoated until a permanent replacement could be implemented (ADAMS Accession No. ML13329A422).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE. including research and development. such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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EPRI. EPRI 1021175, "Recommendations for an Effective Program to Control the Degradation of Buried and Underground Piping and Tanks," (1016456 Revision 1). Palo Alto, California: Electric Power Research Institute. December 23, 2010.

ISO. ISO 15589-1, "Petroleum and Natural Gas Industries–Cathodic Protection of Pipeline Transportation Systems–Part 1: On Land Pipelines." Vernier, Geneva, Switzerland: International Organization for Standardization. November 2003.

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NFPA. NFPA 24, “Standard for the Installation of Private Fire Service Mains and Their Appurtenances.” Quincy, Massachusetts: National Fire Protection Association. 2010.

_____. NFPA 25, “Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems, 2011 Edition.” Quincy, Massachusetts: National Fire Protection Association. 2011.

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XI.M42 INTERNAL COATINGS/LININGS FOR IN-SCOPE PIPING, PIPING COMPONENTS, HEAT EXCHANGERS, AND TANKS

Program Description

Proper maintenance of internal coatings/linings is essential to provide reasonable assurance that the intended functions of in-scope components are met. Degradation of coatings/linings can lead to loss of material or cracking of base materials and downstream effects such as reduction in flow, reduction in pressure, or reduction of heat transfer when coatings/linings become debris. The program consists of periodic visual inspections of internal coatings/linings exposed to closed-cycle cooling water (CCCW), raw water, treated water, treated borated water, wastewater, fuel oil, lubricating oil, air, and condensation. Where the visual inspection of the coated/lined surfaces determines that the coating/lining is deficient or degraded, physical tests are performed, where physically possible, in conjunction with the visual inspection. Electric Power Research Institute (EPRI) Report 1019157, “Guideline on Nuclear Safety-Related Coatings,” provides information about the American Society for Testing and Materials (ASTM) standard guidelines and coatings. American Concrete Institute (ACI) Standard 201.1R, “Guide for Conducting a Visual Inspection of Concrete in Service,” provides guidelines for inspecting concrete. In addition, this program may be used to manage aging effects associated with coatings on external surfaces.

Evaluation and Technical Basis

1 ***Scope of Program:*** The scope of the program is internal coatings/linings for in-scope piping, piping components, heat exchangers, and tanks exposed to CCCW, raw water, treated water, treated borated water, waste water, fuel oil, lubricating oil, air, and condensation, where loss of coating or lining integrity could prevent satisfactory accomplishment of any of the component’s or downstream component’s current licensing basis (CLB) intended functions identified under Title 10 of the *Code of Federal Regulations* (10 CFR) 54.4(a)(1), (a)(2), or (a)(3)(TN4878). The aging effects associated with firewater tank internal coatings/linings are managed by Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M27, “Fire Water System,” instead of this AMP. However, where the firewater storage tank internals are coated, the Fire Water System program and Final Safety Analysis Report (FSAR) Summary Description of the Program should be enhanced to include the recommendations associated with the training and qualification of personnel and the “corrective actions” program element. The Fire Water System program should also be enhanced to include the recommendations from the “acceptance criteria” program element.

If a coating/lining has a qualified life, and it will be replaced prior to the end of its qualified life without consideration of extending the life through condition monitoring, it would not be considered long lived and therefore, it would not be within the scope of this AMP.

Coatings/linings are an integral part of an in-scope component. The CLB-intended function(s) of the component dictates whether the component has an intended function(s) that meets the scoping criteria of 10 CFR 54.4(a). Internal coatings/linings for in-scope piping, piping components, heat exchangers, and tanks are not evaluated as standalone components to determine whether they meet the scoping criteria of 10 CFR 54.4(a). It is immaterial whether the coating/lining has an intended function identified in the CLB because it is the CLB-intended function of the component that dictates whether the component is in-scope and thereby the aging effects of the coating/lining integral to the component must be evaluated for potential impact on the component's and downstream component's intended function(s).

An applicant may elect to manage the aging effects for internal coatings/linings for in-scope piping, piping components, heat exchangers, and tanks in an alternative AMP that is specific to the component or system in which the coatings/linings are installed (e.g., GALL-SLR Report AMP XI.M20, "Open-Cycle Cooling Water System," for service water coatings/linings) as long as the following are met:

- The recommendations of this AMP are incorporated into the alternative program.
- Exceptions or enhancements associated with the recommendations in this AMP are included in the alternative AMP.
- The FSAR supplement for this AMP and the alternative AMP, as shown in the GALL-SLR Report Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs," is included in the application with a reference to the alternative AMP managing the aging effects for internal coatings/linings.

For components for which the aging effects of internally coated/lined surfaces are managed by this program, loss of material, cracking, and loss of material due to selective leaching need not be managed for these components by another program.

This program may be used to manage aging effects associated with external surfaces, as indicated in GALL-SLR Report AMR items and corresponding Standard Review Plan (SRP) for review of-SLR Further Evaluation sections. When the external coatings are credited as isolating the external surface of a component from the environment, the recommendations noted in this AMP are met.

2 ***Preventive Actions:*** The program is a condition monitoring program and does not recommend any preventive actions. However, external coatings can be credited as being a preventive action based on the coating isolating the external surfaces of a component from the environment.

3 ***Parameters Monitored or Inspected:*** Visual inspections are intended to identify coatings/linings that do not meet the acceptance criteria, such as peeling and delamination. Aging mechanisms associated with coatings/linings are as follows:

- blistering – formation of bubbles in a coating/lining
- cracking – formation of breaks in a coating/lining that extend through to the underlying surface
- flaking – detachment of pieces of the coating/lining itself either from its substrate or from previously applied layers
- peeling – separation of one or more coats or layers of a coating/lining from the substrate
- delamination – separation of one coat or layer from another coat or layer, or from the substrate
- rusting – corrosion of the substrate that occurs beneath or through the applied coating/lining.

Loss of material and cracking is managed for cementitious materials. See the term "Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation," in the GALL-SLR Report Chapter IX.F.

Physical damage consists of removal or reduction of the thickness of a coating/lining by mechanical damage. For the purposes of this AMP, this would include damage such as that which could occur downstream of a throttled valve as a result of cavitation or erosion. It does not include physical damage caused by actions such as installing scaffolding or assembling and disassembling flanged joints.

Physical testing is intended to identify the extent of potential degradation of the coating/lining.

4 ***Detection of Aging Effects:*** If a baseline has not been previously established, baseline coating/lining inspections occur during the 10-year period prior to the subsequent period of extended operation. Subsequent inspections are based on an evaluation of the effect of a coating/lining failure on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history. Subsequent inspection intervals are established by a coating specialist qualified in accordance with an ASTM International standard endorsed in Regulatory Guide (RG) 1.54. However, inspection intervals should not exceed those listed in Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers."

The extent of baseline and periodic inspections is based on an evaluation of the effect of a coating/lining failure on the in-scope component's intended function(s), potential problems identified during prior inspections, and known service life history; however, the extent of inspection is not any less than the following for each coating/lining material and environment combination.

- All tanks – all accessible internal surfaces (and external surfaces when credited to isolate the external surfaces of a component from the environment).
- All heat exchangers – all accessible internal surfaces (and external surfaces when credited as isolating the external surfaces of a component from the environment.)
- Piping – either inspect a representative sample of seventy-three 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating/lining type of material and environment combination, whichever is less at each unit. Samples are taken from multiple locations to ensure that a representative sample is examined, focusing on components that are most susceptible to the applicable aging effect. The inspection surface includes the entire inside (or outside when applicable) 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 of seventy-three 1-foot axial length sections. For example, if the remote tool can only be maneuvered to view one-third of the inside surface, 219 feet of pipe are inspected.

  Where documentation exists indicating that manufacturer recommendations and industry consensus documents (i.e., those recommended in RG 1.54, or earlier versions of those standards) were complied with during installation, the extent of piping inspections may be reduced to the lesser of twenty-five 1 foot axial length circumferential segments of piping or 20 percent of the total length of each coating/lining material and environment combination at each unit.

Table XI.M42-1. Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers[a, b]

Inspection Category[c]	Inspection Interval
A	6 years [d]
B[e, f]	4 years

(a) Current licensing basis (CLB) requirements (e.g., Generic Letter 89-13) might require more frequent inspections.
(b) Internal inspection intervals for diesel fuel oil storage tanks may meet either Table XI.M42-1, or if the inspection results meet Inspection Category A, GALL-SLR Report AMP XI.M30, "Fuel Oil Chemistry."
(c) Inspection Categories
1 No peeling, delamination, blisters, or rusting are observed during inspections. Any cracking and flaking have been found to be acceptable in accordance with the "acceptance criteria" program element of this AMP. No cracking or loss of material has been observed in cementitious coatings/linings.
2 Prior inspection results do not meet Category A guidelines.
- As an alternative to conducting inspections at the intervals in inspection Category B, an extent of condition inspection is conducted prior to the end of the next refueling outage. The extent of condition inspections inspects either double the number of components or an additional five piping inspections (i.e., five 1-foot segments of piping). If Inspection Category A criteria are satisfied for the other coatings in the initial sample and the expanded scope, Inspection Category A may be used for subsequent inspections.

(d) If the following conditions are met, the inspection interval may be extended to 12 years:
1. The identical coating/lining 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.
2 The coating/lining is not in a location subject to erosion that could result in damage to the coating/lining (e.g., certain heat exchanger end bells, piping downstream of certain control valves, windborne erosive particles for external coatings).

(e) Subsequent inspections for Inspection Category B are reinspections at the original location(s), when the coatings/linings have not been repaired, replaced, or removed, as well as inspections of new locations.
(f) When conducting inspections for Inspection Category B, if two sequential subsequent inspections demonstrate no change in coating/lining condition (i.e., at least three consecutive inspections with no change in condition), subsequent inspections at those locations may be conducted in accordance with Inspection Category A.

For multi-unit sites where the piping sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections at the site as follows:

- For two-unit sites, fifty-five 1-foot axial length sections of piping (19 if manufacturer recommendations and industry consensus documents were complied with during installation) are inspected per unit.
- For a three-unit site, forty-nine 1-foot axial length sections of piping (17 if manufacturer recommendations and industry consensus documents were complied with during installation) are inspected per unit.
- To conduct the reduced number of inspections, the applicant states in the subsequent license renewal application the basis for why the operating conditions at each unit are similar enough (e.g., flowrate, temperature, excursions) to provide representative inspection results.

The coating/lining environment includes both the environment inside (and outside when applicable) of the component and the metal to which the coating/lining is attached. Inspection locations are selected based on susceptibility to degradation and consequences of failure.

Coating/lining surfaces captured between interlocking surfaces (e.g., flange faces) are not required to be inspected unless the joint has been disassembled to allow access for an internal coating/lining inspection or for other reasons. For areas not readily accessible for direct inspection, such as small pipelines, heat exchangers, and other equipment, consideration is given to the use of remote or robotic inspection tools.

Either of the following options (i.e., Item a or b) is an acceptable alternative to the inspections recommended in this AMP for internal coatings when all of the following conditions exist:

- Loss of coating or lining integrity cannot result in downstream effects such as reduction in flow, drop in pressure, or reduction of heat transfer for in-scope components.
- The component's only CLB intended function is leakage boundary (spatial) or structural integrity (attached), as defined in SRP-SLR Table 2.1-4(b).
- The internal environment does not contain chemical compounds that could cause accelerated corrosion of the base material if coating/lining degradation resulted in exposure of the base metal.
- The internal environment would not promote microbiologically influenced corrosion of the base metal.
- The coated/lined components are not located in the vicinity of uncoated components that could cause a galvanic couple to exist.
- The design of the component did not credit the coating/lining (e.g., the corrosion allowance was not zero).

A representative sample of external wall thickness measurements can be performed every 10 years commencing 10 years prior to the subsequent period of extended operation to confirm the acceptability of the corrosion rate of the base metal. For heat exchangers and tanks, a representative sample includes 25 percent coverage of the accessible external surfaces. For piping, a representative sample size is defined above.

In lieu of external wall thickness measurements, use GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," and GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or other appropriate internal surfaces inspection program (e.g., GALL-SLR Report AMP XI.M20, AMP XI M21A) to manage loss of coating or lining integrity.

In addition, where loss of internal coating or lining integrity cannot result in downstream effects such as reduction in flow, drop in pressure, or reduction of heat transfer for in-scope components, a representative sample of external wall thickness measurements can be performed every 10 years commencing 10 years prior to the subsequent period of extended operation to confirm the acceptability of the corrosion rate of the base metal in lieu of visual inspections of the coatings/linings. For heat exchangers and tanks, a representative sample includes 25 percent coverage of the accessible external surfaces. For piping, a representative sample size is described above.

The training and qualification of individuals involved in performing coating/lining inspections and evaluating degraded conditions is conducted in accordance with an ASTM International standard endorsed in RG 1.54, including staff limitations associated with a particular standard, except for cementitious materials. For cementitious coatings/linings inspectors should have a minimum of 5 years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of 1 year of experience.

Opportunistic inspections, in lieu of periodic inspections, are an acceptable alternative for buried internally lined/coated firewater system piping if the following conditions are met:

(1) flow tests and internal piping inspections will occur at intervals specified in National Fire Protection Association (NFPA) Code 25, or as modified by AMP XI.M27, Table XI.M27-1; (2) through-wall flaws in the piping can be detected through continuous system pressure monitoring; and (3) plant-specific operating experience is acceptable (i.e., there are no leaks due to age-related degradation of representative internal coatings/linings used in buried in-scope firewater system components). If exceptions are taken to Table XI.M27-1 related to flow tests or internal piping inspections, each exception should justify why the exception will not affect the detection of potential internal loss of coating/lining integrity.

5 ***Monitoring and Trending:*** A preinspection review of the previous two inspections, when available (i.e., two sets of inspection results may not be available to review for the baseline and first subsequent inspection of a particular coating/lining location), is conducted that includes reviewing the results of inspections and any subsequent repair activities. A coatings specialist prepares 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.

Where practical, (e.g., wall thickness measurements, blister size and frequency), degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

6 ***Acceptance Criteria:*** Acceptance criteria are as follows:

a. There are no indications of peeling or delamination.

b. Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54, including staff limitations associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size or frequency should not be increasing between inspections (e.g., ASTM D714-02, "Standard Test Method for Evaluating Degree of Blistering of Paints").

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

d. Minor cracking and spalling of cementitious coatings/linings is acceptable if there is no evidence that the coating/lining is debonding from the base material.

e. As applicable, wall thickness measurements, projected to the next inspection, meet minimum wall design requirements.

f. Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in plant-specific design requirements specific to the coating/lining and substrate.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this

AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Coatings/linings that do not meet the acceptance criteria are repaired, replaced, or removed. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material.

As an alternative, internal coatings exhibiting indications of peeling and delamination may be returned to service if (1) physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal; (2) the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered); (3) adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of three sample points adjacent to the defective area; (4) an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component; and (5) follow-up visual inspections of the degraded coating are conducted within 2 years from detection of the degraded condition, with a reinspection within an additional 2 years, or until the degraded coating is repaired or replaced.

If coatings/linings are credited for corrosion prevention (e.g., corrosion allowance in design calculations is zero, the “preventive actions” program element of a subsequent license renewal application AMP credited the coating/lining) 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/lining is examined to determine whether the minimum wall thickness is met and will be met until the next inspection occurs.

When a blister does not meet the acceptance criteria, and it is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain in service should be based on the potential effects of flow blockage and the degradation of the base material beneath the blister.

Additional inspections are conducted if one of the inspections does not meet the acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement of all components constructed of the same material and exposed to the same environment. The number of increased inspections is determined in accordance with the site’s corrective action process; however, there are no fewer than five additional inspections for each inspection that did not meet the acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. When inspections are based on the percentage of piping length, an additional 5 percent of the total length is inspected. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, in all cases, the additional inspections are completed within the interval during which the original inspection was conducted, or if identified during the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited toward the number of inspections in the latter interval. If subsequent inspections do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections needed. Additional samples are inspected for any recurring degradation to provide reasonable assurance that corrective actions appropriately address the associated causes. At multi-unit sites, the additional inspections include inspections at all of the units that have the same material, environment, and aging effect combination.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** The inspection techniques and training of inspection personnel associated with this program are consistent with industry practice and have been demonstrated to be effective at detecting the loss of coating or lining integrity. Inspection intervals that are not be exceeded have been established that are dependent on the results of previous plant-specific inspection results. The following examples describe operating experience (OE) pertaining to loss of coating or lining integrity for coatings/linings installed on the internal surfaces of piping systems:

a. In 1982, a licensee experienced degradation of internal coatings in its spray pond piping system. This issue involves many key aspects related to coating degradation, including installation details such as improper curing time, restricted availability of air flow leading to improper curing, installation layers that were too thick, and improper surface preparation (e.g., oils on surface, surface too smooth). The aging mechanisms included severe blistering, moisture entrapment between layers of the coating, delamination, peeling, and widespread rusting. The failure to install the coatings in accordance with manufacturer recommendations resulted in flow restrictions to the ultimate heat sink and blockage of an emergency diesel generator governor oil cooler (Information Notice 85-24, “Failures of Protective Coatings in Pipes and Heat Exchangers.”)

b. During a U.S. Nuclear Regulatory Commission inspection, the staff found that coating degradation, which occurred as a result of the weakening of the adhesive bond of the coating to the base metal due to turbulent flow, resulted in the coating eroding away and leaving the base metal subject to wall thinning and leakage (Agencywide Documents Access and Management System [ADAMS] Accession No. ML12045A544)].

c. In 1994, a licensee replaced a portion of its cement-lined steel service water piping with piping lined with polyvinyl chloride material. The manufacturer stated that the lining material had an expected life of 15–20 years. An inspection in 1997 showed some bubbles and delamination in the coating material at a flange. A 2002 inspection found some locations that lacked adhesion to the base metal. In 2011, diminished flow was observed downstream of this line. Inspections revealed that most of the lining in one spool piece was loose or missing. The missing material had clogged a downstream orifice. A sample of the lining was sent to a testing lab where it was determined that cracking was evident on both the base metal and water side of the lining, and there was a noticeable increase in the hardness of the inservice sample compared to an unused sample (ADAMS Accession No. ML12041A054).

d. A licensee has experienced multiple instances of coating degradation resulting in coating debris found downstream in heat exchanger end bells. None of the debris had been large enough to result in reduced heat exchanger performance (ADAMS Accession No. ML12097A064).

e. A licensee experienced continuing flow reduction over a 14-day period, resulting in the service water room cooler being declared inoperable. The flow reduction occurred because the rubber coating on a butterfly valve became detached (ADAMS Accession No. ML073200779).

f. At an international plant, cavitation in the piping system damaged the coating of a piping system, which subsequently resulted in unanticipated corrosion through the pipe wall (ADAMS Accession No. ML13063A135).

g. A licensee experienced degradation of the protective concrete lining, which allowed brackish water to contact the unprotected carbon steel piping, resulting in localized corrosion. The degradation of the concrete lining was likely caused by the high flow velocities and turbulence from the valve located just upstream of the degraded area (ADAMS Accession No. ML072890132).

h. A licensee experienced through-wall corrosion when a localized area of coating degradation resulted in base metal corrosion. The cause of the coating degradation is thought to have not been age-related mechanical damage (ADAMS Accession No. ML14087A210).

i. A licensee experienced through-wall corrosion when a localized polymeric repair of a rubber lined spool failed (ADAMS Accession No. ML14073A059).

j. A licensee experienced accelerated galvanic corrosion when loss of coating integrity occurred in the vicinity of carbon steel components attached to AL6XN components (ADAMS Accession No. ML12297A333).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 54.4(a), “Scope.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 54-TN4878

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XI.M43 HIGH-DENSITY POLYETHYLENE (HDPE) PIPING AND CARBON FIBER-REINFORCED POLYMER (CFRP) REPAIRED PIPING

Program Description

This aging management program (AMP) manages the aging of the internal and external surfaces of high-density polyethylene (HDPE) piping and carbon fiber-reinforced polymer (CFRP)-repaired piping. It manages aging through preventive, mitigative, inspection, and in some cases, performance monitoring activities. It manages aging effects such as loss of material, cracking, blistering, and flow blockage.

Depending on the material, preventive and mitigative techniques may include external coatings, cathodic protection of the metal substrate of the terminal ends of the CFRP-repaired piping, and the quality of backfill. Also, depending on the material, inspection activities may include electrochemical verification of the effectiveness of cathodic protection, nondestructive evaluation of pipe wall thicknesses, pressure testing of the pipe, and volumetric inspections and visual inspections of the pipe from the exterior and/or interior.

This program does not provide aging management of the internal surfaces of fire protection system piping. GALL-SLR Report AMP XI.M27, “Fire Water System,” applies for applicable internal environments.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages the effects of the aging of the internal and external surfaces of HDPE piping and CFRP-repaired piping. When HDPE is referenced, it applies to the material that meets the requirements of American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Section III, Mandatory Appendix XXVI, “Rules for Construction of Class 3 Buried Polyethylene Piping”, or as approved by the U.S. Nuclear Regulatory Commission (NRC). When CFRP is referenced, it applies to installation or application of the CFRP repair on the interior surface of a pipe. The program addresses aging effects such as loss of material, cracking, blistering, and flow blockage.

2 ***Preventive Actions:*** Preventive actions used by this program vary with the material of the pipe and the environment (e.g., air, soil, concrete) to which it is exposed. Preventive actions for HDPE piping and CFRP-repaired piping are conducted in accordance with Table XI.M43-1:

Table XI.M43-1. Preventive Actions for HDPE Piping and CFRP Repaired Piping

Material	Buried	Underground
HDPE	B	None
CFRP	CP[(a)]B[(b)]	None

B = backfill; CP = cathodic protection; CFRP = carbon fiber reinforced polymer; high-density polyethylene (HDPE).

(a) The metal substrate of CFRP at the terminal end region may require cathodic protection.

(b) CFRP that is installed on the inside surface of a metal pipe may be affected by the backfill (i.e., metal substrate between terminal ends of CFRP may be degraded completely). The exterior surface of the host metal pipe may be affected by the backfill.

a. Cathodic protection is needed for the existing metal pipe that has the CFRP installed on the interior surface of the pipe (i.e., to ensure metal substrate of the CFRP terminal end region is protected from potential corrosion).

   Cathodic protection is in accordance with National Association of Corrosion Engineers (NACE) Standard SP0169-2007 or NACE RP0285-2002. The cathodic protection system is operated so that the cathodic protection criteria and other considerations described in the standards are met at every location in the system for which cathodic protection is credited. System monitoring is conducted annually with a grace period of 1 to 2 months; however, in each calendar year, system monitoring is conducted at least once. The equipment used to implement cathodic protection need not be qualified in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B.

b. Backfill is consistent with NACE SP0169-2007 Section 5.2.3 or NACE RP0285-2002, Section 3.6. The staff considers backfill that is located within 6 inches of the piping that meets ASTM D 448-08 size number 67 (size number 10 for polymeric piping materials) to meet the objectives of NACE SP0169-2007 and NACE RP0285-2002. Backfill quality may be demonstrated by plant records or by examining the backfill while conducting the inspections described in the "detection of aging effects" program element of this AMP.

c. Alternatives to the preventive actions in Table XI.M43-1 are as follows:

   i. Failure to provide cathodic protection in accordance with Table XI.M43-1 may be acceptable if justified in the subsequent license renewal application (SLRA). The justification addresses soil sample locations, soil sample results, the methodology and results of how the overall soil corrosivity was determined, pipe to soil potential measurements, and other relevant parameters.

   ii. If cathodic protection is not provided for any reason, the applicant reviews the most recent 10 years of plant-specific operating experience (OE) to determine if degraded conditions that would not have met the acceptance criteria of this AMP have occurred. This search includes piping systems that are not in scope for license renewal if, when compared to in-scope piping, they are similar materials and coating systems and are buried in a similar soil environment. The results of this expanded plant-specific OE search are included in the SLRA.

3 ***Parameters Monitored or Inspected:*** Parameters that are monitored or inspected for detection of aging effects vary with the material. Monitoring of the external and/or internal surface condition is conducted to detect loss of material, cracking, disbondment, damage, and leakage. Monitoring of the external surfaces of controlled low-strength material backfill is conducted to detect potential cracks that could admit groundwater to the surface of the piping with a CFRP repair. Volumetric examination may be used to measure wall thickness and detect delamination and/or disbondment in the CFRP-repaired piping.

a. For HDPE piping:

i. Visual inspections of the external and internal surface condition of the HDPE piping should be conducted per the requirements of 10 CFR 50.55a and/or NRC-approved alternative requests. In the absence of any of these requirements, the visual inspections should be performed per vendor and/or manufacturer requirements. The visual inspections should detect:

(1) loss of HDPE material due to wear, radiation, temperature, and moisture,

(2) cracking or blistering of HDPE material (e.g., due to water absorption),

(3) leakage of the pipe from its exterior surface.

(4) accumulation of particulate fouling (raw water systems)

ii. A system leakage test, in accordance with the ASME Code, Section XI, Paragraph IWA-5000, should be performed to detect leakage.

iii. For service water system piping, CLB requirements associated with NRC Generic Letter (GL) 89-13 and associated Supplement 1 are performed.

b. For CFRP repaired piping:

i. Visual inspections of the internal surface condition of the CFRP-repaired piping should be conducted per the requirements of 10 CFR 50.55a and/or NRC-approved alternative requests. In the absence of any of these requirements, the visual inspections should be performed per vendor and/or manufacturer requirements. The visual inspections should detect the following:

(1) loss of CFRP material due to wear, radiation, temperature, moisture;

(2) cracking or blistering of CFRP material (e.g., due to water absorption);

(3) delaminations, tearing, debonding, or voids in CFRP layers;

(4) disbondment of CFRP laminate from substrate at each terminal end region;

(5) loss of assembly components, damage, loss of tension; movement/slippage relative to the end point of CFRP laminate of the expansion ring (or alternatively referred to as compression ring) installed at each CFRP repair’s terminal end;

(6) leakage of the pipe from its exterior surface; and

(7) accumulation of particulate fouling (raw water systems).

ii. Volumetric examination of the terminal end regions of the CFRP-repaired piping should be performed using a nondestructive examination (NDE) technique; e.g., acoustic tap, ultrasonic, electrical, magnetic, thermal, microwave, or other applicable nondestructive methods. The acoustic tap test is a manual NDE method that consists of lightly tapping the surface with a small light-weight hammer that has a spherical tip, or other suitable device, while the human ear is used to monitor the audible acoustic response. The acoustic response is compared to that of a known good area. A “flat” or “dead” response indicates an area of concern.

iii. Interrogate the CFRP-repaired piping at the terminal end region to detect delamination and disbondment,

iv. Establish a thickness profile of the metallic substrate at the terminal end region to verify conformance with design requirements.

c. A system leakage test in accordance with the ASME Code, Section XI, Paragraph IWA-5000 should be performed to detect leakage.

d. For service water system piping, CLB requirements associated with NRC Generic Letter (GL) 89-13 and associated Supplement 1 should be performed.

4 ***Detection of Aging Effects:*** Methods and frequencies used for the detection of aging effects vary based on the material and environment. Opportunistic inspections are conducted for HDPE piping and CFRP-repaired piping whenever they become accessible. In addition, periodic inspections are conducted in accordance with Table XI.M43-2 and the following. Table XI.M43-2 inspection quantities are for a single-unit plant. For two-unit sites, the inspection quantities (i.e., not the percentage of pipe length) are increased by 50 percent. For a three-unit site, the inspection quantities are doubled. For multi-unit sites, the inspections are distributed evenly among the units. Additional inspections, beyond those listed in Table XI.M43-2, may be appropriate if exceptions are taken to program element 2, “preventive actions,” or in response to plant-specific OE.

Inspections are conducted during each 10-year period, commencing 10 years prior to the subsequent period of extended operation. Inspections are conducted in accordance with “Parameters Monitored or Inspected” and “Detection of Aging Effects” program elements. Visual inspections are supplemented with surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed.

Table XI.M43-2. Inspection of Buried and Underground HDPE and CFRP Piping
Inspections of Buried HDPE and CFRP Piping

Material	Preventive Action Categories	Inspection See Section 4.c. for Extent of Inspections
High-density polyethylene (HDPE)	Backfill is in accordance with the preventive actions program element	1 pipe segment inspection
	Backfill is not in accordance with the preventive actions program element	The smaller of 1% of the length of pipe run or 2 pipe segment inspections
Carbon fiber - reinforced polymer (CFRP)	Backfill is in accordance with the preventive actions program element	1 pipe segment inspection
	Backfill is not in accordance with the preventive actions program element	The smaller of 1% of the length of pipe run or 2 pipe segment inspections
Steel (Metallic substrate of CFRP)	A	The smaller of 0.5% of the length of pipe run or 1 pipe segment inspection
	B	The smaller of 1% of the length of pipe run or 2 pipe segment inspections
	C	The smaller of 5% of the length of pipe run or 3 pipe segment inspections
	D	The smaller of 10% of the length of pipe run or 6 pipe segment inspections
Inspections of Underground HDPE and CFRP Piping		
Material	**Underground HDPE and CFRP Piping**	
HDPE	1 pipe segment inspection	
CFRP	1 pipe segment inspection	
Steel (Metallic substrate of CFRP)	The smaller of 2% of the piping length or 2 inspections	

The Preventive Action Categories are used as follows:

A: Category A applies when the following are true

a. Cathodic protection was installed or refurbished 5 years prior to the end of the inspection period of interest.
b. Cathodic protection has operated at least 85% of the time either since 10 years prior to the subsequent period of extended operation or since installation/refurbishment, whichever is shorter. Time periods in which the cathodic protection system is off-line for testing do not have to be included in the total nonoperating hours.
c. Cathodic protection has provided effective protection of buried piping as evidenced by meeting the acceptance criteria of Table XI.M43-3 of this AMP at least 80% of the time, either since 10 years prior to the subsequent period of extended operation or since installation/refurbishment, whichever is shorter. As-found results of annual surveys are to be used to determine locations within the plant's population of buried pipe where cathodic protection acceptance criteria have, or have not, been met.

B: Inspection criteria provided for Category B piping may be used for the portions of in-scope buried piping for which it has been determined, in accordance with the "preventive actions" program element of this AMP, that external corrosion control is not required.

C: Inspection criteria provided for Category C piping may be used for the portions of the population of buried piping for which

a. An analysis, conducted in accordance with the “preventive actions” program element of this AMP, has determined that installation or operation of a cathodic protection system is impractical; or
b. A cathodic protection system has been installed but all or portions of the piping covered by that system fail to meet any of the criteria of Category A piping above, provided:
    i. coatings and backfill are provided in accordance with the “preventive actions” program element of this AMP;
    ii. plant-specific OE is acceptable (i.e., no leaks in buried piping due to external corrosion, no significant coating degradation or metal loss in more than 10% of inspections conducted); and
    iii. soil has been determined to not be corrosive for the material type (e.g., AWWA C105, “Polyethylene Encasement for Ductile-Iron Pipe Systems,” Table A.1, “Soil-Test Evaluation”).

    In order to determine that the soil is not corrosive, the applicant:
    1) Obtains a minimum of three sets of soil samples in each soil environment (e.g., moisture content, soil composition) in the vicinity in which in-scope piping is buried.
    2) Tests the soil for soil resistivity, corrosion-accelerating bacteria, pH, moisture, chlorides, sulfates, and redox potential.
    3) Determines the potential soil corrosivity for each material type of buried in-scope piping. In addition to evaluating each individual parameter, the overall soil corrosivity is determined.
    4) Conducts soil testing once in each 10-year period starting 10 years prior to the subsequent period of extended operation.

D: Inspection criteria provided for Category D piping are used for the portions of in-scope buried piping that cannot be classified as Category A, B, or C.

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a. <u>Transitioning to a Higher Number of Inspections</u>: Plant-specific conditions can result in transitioning to a higher number of inspections than originally planned at the beginning of a 10-year interval. For example, degraded performance of the cathodic protection system could result in transitioning from Preventive Action Category A to Preventive Action Category C. The coating, backfill, or condition of exposed piping that do not meet acceptance criteria could result in transitioning from Preventive Action Category C to Preventive Action Category D. If this transition occurs in the latter half of the current 10-year interval, the timing of the additional examinations is based on the severity of the degradation identified and is commensurate with the consequences of a leak or loss of function, but in all cases, the examinations are completed within 4 years after the end of the particular 10-year interval. The additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited toward the number of inspections stated in Table XI.M43-2 for the following 10-year interval.

b. Exceptions to Table XI.M43-2 inspection quantities (except for opportunistic inspections):

    i. For buried HDPE piping and CFRP-repaired piping, inspections may be reduced to one-half the number of inspections indicated in Table XI.M43-2 when performance of the indicated inspections necessitates excavation of piping that has been fully backfilled using controlled low-strength material. The inspection quantity is rounded up (e.g., where three inspections are recommended in Table XI.M43-2, two inspections are conducted). When conducting inspections of buried piping embedded in concrete backfill, the backfill may be excavated and the piping examined, or the soil around the backfill may be excavated and the concrete backfill material examined. The inspection includes excavation of the top surfaces and at least 50 percent of the side surface to visually inspect for cracks in the backfill that could admit groundwater to the external surfaces of the pipe. When conducting inspection of backfill based on the number of inspections, 10 linear feet of the backfill are exposed for each inspection.

ii. If all of the in-scope HDPE piping and CFRP-repaired piping are non-safety-related, no more than one inspection needs to be conducted.

c. Guidance related to the extent of inspections for HDPE piping and CFRP-repaired piping is as follows:

i. When the inspections are based on the number of inspections in lieu of the percentage of piping length, a minimum pipe segment of 10 feet in the piping run is exposed for each inspection.

ii. When the percentage of inspections for a given material type results in an inspection quantity of less than 10 feet in a piping segment, then a minimum of 10 feet of piping is to be inspected. If the entire run of piping of that material type is less than 10 feet in total length, then the entire run of piping is to be inspected.

iii. If CFRP is installed on the interior surface of the existing metal pipe, the terminal ends of the CFRP layers must be inspected by ultrasonic examination during each inspection interval.

d. Piping inspection location selection: Piping inspection locations are selected based on risk (i.e., susceptibility to degradation and consequences of failure). Characteristics such as coating type (i.e., material type), coating condition, cathodic protection efficacy, backfill characteristics, soil resistivity, pipe contents, and pipe function are considered. Opportunistic examinations of nonleaking pipes may be credited toward examinations if the location selection criteria are met. The use of guided wave ultrasonic examinations may not be substituted for the inspections listed in the table.

e. An alternative to the periodic visual examination of piping in Table XI.M43-2 is as follows (alternative not applicable for opportunistic inspections):

i. At least 25 percent of the in-scope HDPE piping and CFRP-repaired piping is pressure tested on an interval not to exceed 5 years. The piping is pressurized to 110 percent of the design pressure of any piping within the boundary (not to exceed the maximum allowable test pressure of any non-isolated piping) and the test pressure is held for a continuous 8-hour interval.

5 ***Monitoring and Trending:*** For piping protected by cathodic protection systems, potential differences and current measurements are trended to identify changes in the effectiveness of the systems and/or coatings. Likewise, if leak rate testing is conducted, leak rates are trended. Where wall thickness measurements are conducted for the CFRP-repaired piping, the results are trended when follow-up examinations are conducted.

Where practical, all other degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the piping’s intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

6 ***Acceptance Criteria:*** The acceptance criteria associated with this AMP are described below.

a. HDPE piping

i. Cracking is absent in HDPE piping. Blisters, gouges, or wear of piping are evaluated in accordance with the “corrective actions” program element specified in Section 7 below.

ii. Backfill is acceptable if the inspections do not reveal evidence that the backfill caused damage to the piping's coatings or the surface of the piping.

iii. For pressure tests, the test acceptance criteria are that there are no visible indications of leakage, and no drop in pressure within the isolated portion of the piping that is not accounted for by a temperature change in the test media or by quantified leakage across test boundary valves.

iv. Any surface scratches and blemishes greater than 10 percent of the thickness on the HDPE piping need to be evaluated.

b. CFRP-repaired piping

i. For externally coated CFRP-repaired piping, there is either no evidence of coating degradation, or the type and extent of coating degradation is evaluated as being insignificant by the plant operator, who (1) has a NACE Coating Inspector Program Level 2 or 3 inspector qualification; (2) has completed the Electric Power Research Institute (EPRI) Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course; or (3) by a coatings specialist qualified in accordance with an ASTM standard endorsed in Regulatory Guide 1.54, Revision 2, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants."

ii. Cracking is absent in CFRP laminate repair layers. Blisters, gouges, or wear of nonmetallic piping are evaluated in accordance with the "corrective actions" program element specified in Section 7 below

iii. The measured wall thickness that is extrapolated to degrade with a loss of material to the end of the period of extended operation or subsequent period of extended operation shall meet minimum wall thickness requirements.

iv. For pressure tests, the test acceptance criteria are that there are no visible indications of leakage, and no drop in pressure within the isolated portion of the piping that is not accounted for by a temperature change in the test media or by quantified leakage across test boundary valves.

v. Delamination, tearing, debonding, or voids in the CFRP laminate at the terminal end region are unacceptable.

vi. Disbondment of CFRP laminate from metallic substrate at each CFRP repair's terminal end region is unacceptable.

vii. Delaminations, tearing, or voids in the CFRP laminate other than terminal end regions are unacceptable.

viii. Backfill is acceptable if the inspections do not reveal evidence that the backfill caused damage to the piping's external coatings or the surface of the pipe.

ix. Criteria for pipe-to-soil potential when using a saturated copper/copper sulfate reference electrode (CSE) are as stated in Table XI.M43-3, or in the acceptable alternatives as stated below.

Table XI.M43-3. Cathodic Protection Acceptance Criteria

Material	Criteria[a, b]
Steel	−850 mV relative to a CSE, instant off
Copper alloy	100 mV minimum polarization
Aluminum alloy	100 mV minimum polarization

(a) Plants with sacrificial anode systems state the test method and acceptance criteria and the basis for the method and criteria in the application.
(b) For steel piping, when (1) active microbiologically influenced corrosion has been identified or is probable; (2) temperatures greater than 60 °C (140 °F); or (3) in weak acid environments, a polarized potential of -950 mV or more negative is recommended.

x. Alternatives to the -850 mV criterion for steel piping in Table XI.M43-3 are as follows:

(1) 100 mV minimum polarization

(2) -750 mV relative to a CSE, instant off where soil resistivity is greater than 10,000 ohm-cm to less than 100,000 ohm-cm

(3) -650 mV relative to a CSE, instant off where soil resistivity is greater than 100,000 ohm-cm

(4) Verify less than 1 mil per year (mpy) loss of material. Loss of material rates in excess of 1 mpy may be acceptable if an engineering evaluation demonstrates that the corrosion rate would not result in a loss of intended function prior to the end of the period of extended operation or subsequent period of extended operation. The engineering evaluation is cited and summarized in the SLRA.

When using the 100 mV, -750 mV, or -650 mV polarization criteria as an alternative to the -850 mV criterion for steel piping, a means of verifying the effectiveness of the protection of the most anodic metal is incorporated into the program. One acceptable means of verifying the effectiveness of the cathodic protection system, or of demonstrating that the loss of material rate is acceptable, is to use installed electrical resistance corrosion rate probes. The external loss of material rate is verified:

- Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate.
- Every 2 years when using the 100 mV minimum polarization.
- Every 5 years when using the -750 or -650 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.

As an alternative to verifying the effectiveness of the cathodic protection system every 5 years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of 10 annual consecutive soil samples, soil resistivity testing can be extended to every 5 years if the results of the soil sample tests consistently verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, all soil resistivity values were greater than 10,000 ohm-cm).

When electrical resistance corrosion rate probes will be used, the application identifies:

- The qualifications of the individuals who will determine the installation locations of the probes and the methods of use (e.g., NACE CP4, “Cathodic Protection Specialist”).
- How the impact of significant site features (e.g., large cathodic protection current collectors, shielding due to large objects located in the vicinity of the protected piping) and local soil conditions will be factored into placement of the probes and use of probe data.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

a. Where the piping does not meet the acceptance criteria, the degraded condition is repaired or the affected piping is replaced. In addition, where the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the subsequent period of extended operation, an expansion of sample size is conducted. The number of inspections within the affected piping categories is doubled or increased by five, whichever is smaller. If the acceptance criteria are not met in any of the expanded samples, an analysis is conducted to determine the extent of the condition and the extent of the cause. The number of follow-on inspections is determined based on the extent of condition and extent of cause.

   The timing of the additional examinations is based on the severity of the degradation identified and is commensurate with the consequences of a leak or loss of function. However, in all cases, the expanded sample inspection is completed within the 10-year interval during which the original inspection was conducted or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval. These additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited toward the number of inspections for the following 10-year interval. The number of inspections may be limited by the extent of piping subject to the observed degradation mechanism.

   The expansion of sample inspections may be halted in a piping system or portion of system that will be replaced within the 10-year interval during which the inspections were conducted or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval.

b. Unacceptable cathodic protection survey results are entered into the plant corrective action program.

c. Sources of leakage detected during pressure tests are identified and corrected.

d. Indications of cracking are evaluated in accordance with applicable codes and plant-specific design criteria.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10

CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** OE shows that pipes with CFRP repairs could be degraded. It is necessary for the applicant to evaluate both plant-specific and nuclear industry OE and to modify its AMP accordingly. The following example of industry experience may be of significance to an applicant's program:

In October 2021, a carbon fiber wrap installed on the inner diameter of a circulating water return piping was found to be degraded. A section of the wrap was completely missing from the pipe wall and found to have relocated to the metallic screens. The carbon fiber wrap was installed due to corrosion to ensure adequate operating margin to prevent future leakage and/or rupture. With sections of the wrap missing the circulating water pipe would be susceptible to continued corrosion.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," Washington, DC: U.S. Nuclear Regulatory Commission, 2016.

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EPRI. EPRI 1021175, "Recommendations for an Effective Program to Control the Degradation of Buried and Underground Piping and Tanks," (1016456 Revision 1), Palo Alto, California: Electric Power Research Institute, December 23, 2010.

ISO. ISO 15589-1, "Petroleum and Natural Gas Industries–Cathodic Protection of Pipeline Transportation Systems–Part 1: On Land Pipelines," Vernier, Geneva, Switzerland: International Organization for Standardization, November 2003.

NRC Generic Letter 89-13, "Service Water Systems Problems Affecting Safety Related Equipment."

NRC Generic Letter 89-13, "Service Water Systems Problems Affecting Safety Related Equipment," Supplement 1. A

ASME Code, Section III, Mandatory Appendix XXVI – Rules for Construction of Class 3 Buried Polyethylene Piping

XI.S STRUCTURAL

XI.S1 ASME SECTION XI, SUBSECTION IWE

Program Description

Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a (TN249) imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code),[1] Section XI, Subsection IWE, for steel containments (Class MC) and steel liners for concrete containments (Class CC). The scope of Subsection IWE includes steel containment shells and their integral attachments, steel liners for concrete containments and their integral attachments, containment penetrations, hatches, airlocks, moisture barriers, and pressure-retaining bolting. The requirements of ASME Code, Section XI, Subsection IWE, with the additional requirements specified in 10 CFR 50.55a(b)(2), are supplemented herein to augment an existing program applicable to managing the aging of steel containments, steel liners of concrete containments, and other containment components for the subsequent period of extended operation.

The primary ISI method specified in IWE is visual examination (General Visual, VT-3, VT-1). Limited volumetric examination (ultrasonic thickness measurement) and surface examination (e.g., liquid penetrant) may also be necessary in some instances to detect aging effects. IWE specifies acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria are found.

Subsection IWE requires examination of coatings that are intended to prevent corrosion. Aging management program (AMP) XI.S8 is a protective coating monitoring and maintenance program that is recommended to provide reasonable assurance of emergency core cooling system (ECCS) operability, whether or not the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.S8 is credited in the GALL-SLR Report AMP XI.S1.

The program attributes are supplemented to incorporate the aging management activities, recommended in the Final License Renewal Interim Staff Guidance (LR-ISG)-2006-01, that are needed to address the potential loss of material due to corrosion in the inaccessible areas of the boiling water reactor (BWR) Mark I steel containment.

The program attributes are supplemented to consider the operating experience (OE) of two-ply bellows for detection of cracking described in the U.S. Nuclear Regulatory Commission (NRC) Information Notice (IN) 92-20, "Inadequate Local Leak Rate Testing," and to also include preventive actions to provide reasonable assurance that bolting integrity is maintained. The program is also supplemented to include performance of surface examinations of pressure-retaining components that are subject to cyclic loading but have no current licensing basis (CLB) fatigue analysis; and, based on plant-specific OE, a one-time volumetric examination of metal shell or liner surfaces that are inaccessible from one side.

Evaluation and Technical Basis

1 ***Scope of Program:*** The scope of this program addresses the pressure-retaining components of steel containments and steel liners of concrete containments specified in

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

Subsection IWE-1000 and it is supplemented to address aging management of potential corrosion in inaccessible areas of the drywell shell exterior of BWR Mark I steel containments. The components within the scope of Subsection IWE are Class Metal Containment (MC) pressure-retaining components (steel containments) and their integral attachments, metallic shell and penetration liners of Class CC containments and their integral attachments, containment moisture barriers, containment pressure-retaining bolting, and metal containment surface areas, including welds and base metal. The concrete portions of containments are inspected in accordance with Subsection IWL. Subsection IWE requires examination of coatings that are intended to prevent corrosion, including those inside BWR suppression chambers. The GALL-SLR Report AMP XI.S8 is a protective coating monitoring and maintenance program that is recommended to provide reasonable assurance of ECCS operability, whether or not the GALL-SLR Report AMP XI.S8 is credited in GALL-SLR Report AMP XI.S1.

Subsection IWE exempts the following from examination:

- components that are outside the boundaries of the containment, as defined in the plant-specific design specification;
- embedded or inaccessible portions of containment components that met the requirements of the original construction code of record;
- components that become embedded or inaccessible as a result of containment structure (i.e., steel containments [Class MC] and steel liners of concrete containments [Class CC]) repair or replacement, if the requirements of IWE-1232 and IWE-5220 are met; and
- piping, pumps, and valves that are part of the containment system or that penetrate or are attached to the containment vessel (governed by IWB or IWC).

10 CFR 50.55a(b)(2)(ix)(TN249) and IWE-2420 (2006 and later editions/addenda) specify additional requirements for inaccessible areas. They state that the licensee is to evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation of such inaccessible areas. Examination requirements for containment supports are not within the scope of Subsection IWE.

2 ***Preventive Action:*** This is a condition monitoring program. The program is supplemented to include preventive actions that provide reasonable assurance that moisture levels associated with an accelerated corrosion rate do not exist in the exterior portion of the BWR Mark I steel containment drywell shell. The actions consist of ensuring that the sand pocket area drains and/or the refueling seal drains are clear. The program is also supplemented to include preventive actions to provide reasonable assurance that bolting integrity is maintained, as discussed in Electric Power Research Institute (EPRI) documents (such as EPRI NP-5067 and TR-104213), American Society for Testing and Materials (ASTM) standards, and American Institute of Steel Construction specifications, as applicable. The preventive actions should emphasize proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. If the structural bolting consists of ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts, and the ASTM F3125 specification, which consolidates and replaces high-strength structural bolting standards), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” need to be considered.

3 ***Parameters Monitored or Inspected:*** Table IWE-2500-1 references the applicable sections in IWE-2300 and IWE-3500 that identify the parameters examined or monitored. Noncoated surfaces are examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities including discernible liner plate bulges. Painted or coated surfaces, including those inside BWR suppression chambers, are examined for evidence of flaking, blistering, peeling, discoloration, and other signs of potential distress of the underlying metal shell or liner system, including discernible liner plate bulges. Steel, stainless steel (SS), and dissimilar metal weld pressure-retaining components that are subject to cyclic loading but have no CLB fatigue analysis (i.e., components covered by Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants [SRP-SLR] Table 3.5-1, Items 27 and 40, and corresponding GALL-SLR items; as applicable), are monitored for cracking. The moisture barriers are examined for wear, damage, erosion, tear, surface cracks, or other defects that permit intrusion of moisture in the inaccessible areas of the pressure-retaining surfaces of the metal containment shell or liner. Pressure-retaining bolting is examined for loosening and material conditions that cause the bolted connection to affect either containment leak-tightness or structural integrity.

Subsequent license renewal applicants with BWR Mark I steel containments should periodically monitor the sand pocket area drains and/or the refueling seal drains for water leakage. The applicants should also ensure the drains are clear to prevent moisture levels associated with accelerated corrosion rates in the exterior portion of the drywell shell.

4 ***Detection of Aging Effects:*** The examination methods, frequency, and scope of examination specified in 10 CFR 50.55a (TN249) and Subsection IWE provide reasonable assurance that aging effects are detected before they compromise the design basis requirements. IWE-2500-1 and the requirements of 10 CFR 50.55a provide information regarding the examination categories, parts examined, and examination methods to be used to detect aging.

Regarding the extent of examination, all accessible surfaces receive at least a General Visual examination as specified in Table IWE-2500-1 and the requirements of 10 CFR 50.55a, and the results are evaluated in accordance with IWE-3100. The acceptability of inaccessible areas of the steel containment shell or concrete containment steel liner is evaluated when conditions found in accessible areas could indicate the presence of, or could result in, flaws or degradation in such inaccessible areas. IWE-1240 requires augmented examinations (Examination Category E-C) of containment surface areas that are subject to accelerated degradation and aging. A VT-1 visual examination is performed for areas accessible from both sides, and volumetric (ultrasonic thickness measurement) examination is performed for areas accessible from only one side.

The requirements of ASME Code Section XI, Subsection IWE and 10 CFR 50.55a are supplemented to perform surface examinations (or other applicable techniques) in addition to visual examinations to detect cracking in steel, SS, and dissimilar metal weld pressure-retaining components that are subject to cyclic loading but have no CLB fatigue analysis (i.e., components covered by SRP-SLR Table 3.5-1, Items 27 and 40, and corresponding GALL-SLR items; as applicable to the plant). Where feasible, appropriate Appendix J leak rate tests (GALL-SLR Report AMP XI.S4) capable of detecting cracking may be performed or credited in lieu of the supplemental surface examination; the type of leak test determined to be appropriate is identified with the basis for components for which this option is used.

The requirements of ASME Code Section XI, Subsection IWE and 10 CFR 50.55a are further supplemented to require a one-time volumetric examination of metal shell or liner surfaces that are inaccessible from one side, only if triggered by plant-specific OE. The trigger for this supplemental examination is the plant-specific occurrence or recurrence of measurable metal shell or liner corrosion (base metal material loss exceeding 10 percent of nominal plate thickness) initiated on the inaccessible side or areas, identified since the date of issuance of the first renewed license. This supplemental volumetric examination consists of a sample of 1-foot square locations that include both randomly selected and focused areas most likely to experience degradation based on OE and/or other relevant considerations such as environment. Any identified degradation is addressed in accordance with the applicable provisions of the AMP. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations should be determined on a plant-specific basis to demonstrate statistically with 95 percent confidence that 95 percent of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than a 10 percent loss of nominal thickness. Guidance provided in EPRI TR–107514 may be used for sampling considerations.

5 ***Monitoring and Trending:*** With the exception of inaccessible areas, all surfaces are monitored by virtue of the examination requirements on a scheduled basis.

IWE-2420 specifies that:

- The sequence of component examinations established during the first inspection interval shall be repeated during successive intervals, to the extent practical.
- When examination results require evaluation of flaws or areas of degradation in accordance with IWE-3000, and the component is acceptable for continued service, the areas containing such flaws or areas of degradation shall be reexamined during the next inspection period listed in the schedule of the inspection program of IWE-2411 or IWE-2412, in accordance with Table IWE-2500-1, Examination Category E-C.
- When the reexaminations required by IWE-2420(b) reveal that the flaws or areas of degradation remain essentially unchanged for the next inspection period, these areas no longer require augmented examination in accordance with Table IWE-2500-1 and the regular inspection schedule is continued.

IWE-3120 requires examination results to be compared with recorded results of prior inservice examinations and evaluated for acceptance.

Applicants for subsequent license renewal (SLR) for plants with BWR Mark I containment should augment IWE monitoring and trending requirements to address inaccessible areas of the drywell. The applicant should consider the following recommended actions based on plant-specific design and OE.

a. Develop a corrosion rate that can be inferred from past ultrasonic testing (UT) examinations or establish a corrosion rate using representative samples in similar operating conditions, materials, and environments. If degradation has occurred, provide a technical basis using the developed or established corrosion rate to demonstrate that the drywell shell will have sufficient wall thickness to perform its intended function through the subsequent period of extended operation.

b. Demonstrate that UT measurements performed in response to NRC Generic Letter (GL) 87-05, “Request for Additional Information Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells,” did not show degradation inconsistent with the developed or established corrosion rate.

6 ***Acceptance Criteria:*** IWE-3000 provides acceptance standards for components of steel containments and liners of concrete containments. IWE-3410 refers to criteria to evaluate the acceptability of the containment components for service following the preservice examination and each inservice examination. Most of the acceptance standards rely on visual examinations. Areas identified as having damage or degradation that exceeds acceptance standards require an engineering evaluation or require correction by repair or replacement. For some examinations, such as augmented examinations, numerical values are specified for the acceptance standards. For the containment steel shell or liner, material loss locally exceeding 10 percent of the nominal containment wall thickness or material loss that is projected to locally exceed 10 percent of the nominal containment wall thickness before the next examination is documented. Such areas of material loss are corrected by repair or replacement in accordance with IWE-3122 or accepted by engineering evaluation. Cracking of steel, SS, and dissimilar metal weld pressure-retaining components that are subject to cyclic loading but have no CLB fatigue analysis (i.e., components covered by SRP-SLR Table 3.5-1, Items 27 and 40, and corresponding GALL-SLR items; as applicable) is corrected by repair or replacement or accepted by engineering evaluation.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B (TN249). Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective action element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Subsection IWE states that components whose examination results indicate flaws or areas of degradation that do not meet the acceptance standards listed in IWE-3500 are acceptable if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment. Components that do not meet the acceptance standards are subject to additional examination requirements, and the components are repaired or replaced to the extent necessary to meet the acceptance standards of IWE-3000. For repair of components within the scope of Subsection IWE, IWE-3124 states that repairs and re-examinations are to comply with IWA-4000. IWA-4000 provides repair specifications for pressure-retaining components, including metal containments and metallic liners of concrete containments.

For BWR Mark I steel containments, if moisture has been detected or suspected in the inaccessible area on the exterior of the containment drywell shell or the source of moisture cannot be determined subsequent to root cause analysis, then take the following actions:

a. Include in the scope of the SLR any components that are identified as a source of moisture, if applicable, such as the refueling seal or cracks in the SS liners of the refueling cavity pool walls, and perform an aging management review.

b. Pursuant to Subsection IWE-1240, identify in the inspection program-affected drywell surfaces requiring augmented examination for the subsequent period of extended operation in accordance with Table IWE-2500-1, Examination Category E-C.

c. Conduct augmented inspections of the identified drywell surfaces using examination methods that are in accordance with Subsection IWE-2500.

d. Demonstrate, through use of augmented inspections performed in accordance with Subsection IWE, that corrosion is not occurring or that corrosion is progressing so slowly that the age-related degradation will not jeopardize the intended function of the drywell shell through the subsequent period of extended operation.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. If the evaluation determines that repair or replacement is necessary, Subsection IWE specifies confirmation that appropriate corrective actions have been completed and are effective. Subsection IWE states that repairs and re-examinations are to comply with the requirements of IWA-4000. Re-examinations are conducted in accordance with the requirements of IWA-2200, and the recorded results are to demonstrate that the repair meets the acceptance standards set forth in IWE-3500.

9 ***Administrative Controls*****:** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

IWA-6000 provides specifications for the preparation, submittal, and retention of records and reports.

10 ***Operating Experience*****:** ASME Code Section XI, Subsection IWE, was incorporated into 10 CFR 50.55a (TN249) in 1996. Prior to that time, OE pertaining to degradation of steel components of containment was gained through the inspections required by 10 CFR Part 50, Appendix J and adhoc inspections conducted by licensees and the NRC. NRC IN 86-99, IN 88-82, IN 89-79, IN 2004-09, IN 2010-12, NUREG–1522, and NUREG/CR-7111 described occurrences of corrosion in steel containment shells, containment liners, and tori. NRC GL 87-05 addressed the potential for corrosion of BWR Mark I steel drywells in the "sand pocket region." IN 2011-15 described occurrences of corrosion in BWR Mark I steel containments, both inside the suppression chamber (torus) and outside the drywell. IN 2014-07 described OE concerning degradation of floor weld leak-chase channel systems of the steel containment shell and concrete containment steel liner that could affect leak tightness and aging management of containment structures.

NRC IN 97-10 identified specific locations where concrete containments are susceptible to liner plate corrosion; IN 92-20 described instances of two-ply containment bellows cracking for which leak rate testing was inadequate for crack detection, resulting in loss of leak tightness. Based on occurrences of transgranular stress corrosion cracking, NUREG–1611 (Tables 1 and 2) recommends augmented examination of the surfaces of two-ply bellow bodies using qualified enhanced techniques so that cracking can be detected. Other OE indicates that foreign objects embedded in concrete have caused through-wall corrosion of the liner plate at a few plants that have reinforced concrete containments. NRC Technical Report, "Containment Liner Corrosion Operating Experience Summary" dated August 2, 2011, summarizes the industry OE related to containment liner corrosion and containment liner bulges. Some examples of OE related to liner bulges are noted in NUREG–1522 and Enclosure 2 to NRC Inspection Progress Report 05000302/2011009 dated May 12, 2011.

NRC IN 2006-01 described through-wall cracking and its probable cause in the torus of a BWR Mark I containment. The cracking was identified by the licensee in the heat-affected zone at the high-pressure coolant injection (HPCI) turbine exhaust pipe torus penetration. The licensee concluded that the cracking was most likely initiated by cyclic loading due to condensation oscillation during HPCI operation. These condensation oscillations induced on the torus shell may have been excessive due to the lack of an HPCI turbine exhaust pipe sparger that many other licensees have installed.

The program is to consider the liner plate and containment shell corrosion and cracking concerns described in these generic communications and technical report. Implementation of the ISI requirements of Subsection IWE, in accordance with 10 CFR 50.55a, augmented to consider OE, and as recommended in LR-ISG-2006-01, is a necessary element of aging management for steel components of steel and concrete containments through the subsequent period of extended operation.

Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred as a result of boric acid corrosion, stress corrosion cracking (SCC), and fatigue loading (NRC Inspection and Evaluation Bulletin [IEB] 82-02, NRC GL 91-17). SCC has occurred in high-strength bolts used for nuclear steam supply system component supports (EPRI NP-5769).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

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XI.S2 ASME SECTION XI, SUBSECTION IWL

Program Description

Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a (TN249) imposes the examination requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, Subsection IWL,[1] for reinforced and prestressed concrete containments (Class CC). The scope of IWL includes reinforced concrete and unbonded post-tensioning systems. ASME Code, Section XI, Subsection IWL and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing mandated program applicable to managing the aging of containment reinforced concrete and unbonded post-tensioning systems, and are supplemented herein, for subsequent license renewal. Containments with grouted tendons may require an additional plant-specific aging management program (AMP), based on the guidance in U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.90, "Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons," to address the adequacy of prestressing forces.

The primary inspection method specified in IWL-2500 is visual examination, supplemented by testing. For prestressed containments, tendon wires are tested for yield strength, ultimate tensile strength, and elongation. The tendon corrosion protection medium is analyzed for alkalinity, water content, and soluble ion concentrations. The quantity of free water contained in the anchorage end cap and any free water that drains from tendons during the examination are documented. Samples of free water are analyzed for pH. Prestressing forces are measured in selected sample tendons. IWL specifies acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria are found.

The ASME Code specifies augmented examination requirements following post-tensioning system repair/replacement activities.

Evaluation and Technical Basis

1 ***Scope of Program:*** Subsection IWL-1000 specifies the components of concrete containments within its scope. The components within the scope of Subsection IWL are reinforced concrete and the unbonded post-tensioning systems of Class CC containments, as defined by CC-1000. The program also includes testing of the tendon corrosion protection medium and the pH of free water. Subsection IWL exempts from examination portions of the concrete containment that are inaccessible (e.g., concrete covered by liner, foundation material, or backfill or obstructed by adjacent structures or other components).

10 CFR 50.55a(b)(2)(viii) and the 2009 and later editions/addenda of the ASME Code specify additional requirements for inaccessible areas. The Code states that the licensee is to 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, such inaccessible areas. Steel liners for concrete containments and their integral attachments are not within the scope of Subsection IWL but are included in the scope of Subsection IWE. Subsection IWE is evaluated in Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.S1, "ASME Section XI, Subsection IWE."

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

2 ***Preventive Action:*** ASME Code Section XI, Subsection IWL is a condition monitoring program. However, the program includes actions to prevent or minimize corrosion of the prestressing tendons by maintaining corrosion protection medium chemistry within acceptable limits specified in Subsection IWL.

3 ***Parameters Monitored or Inspected:*** Table IWL-2500-1 specifies two categories for examination of concrete surfaces: (1) Category L-A for all accessible concrete surfaces and (2) Category L-B for concrete surfaces surrounding anchorages of tendons selected for testing in accordance with IWL-2521. Both of these categories rely on visual examination methods. Concrete surfaces are examined for evidence of damage or degradation, such as concrete cracks. IWL-2510 specifies that concrete surfaces are examined for conditions indicative of degradation, such as those defined in American Concrete Institute (ACI) 201.1R and ACI 349.3R. Table IWL-2500-1 also specifies Category L-B for test and examination requirements for unbonded post-tensioning systems. The number of tendons selected for examination is in accordance with Table IWL-2521-1. Additional augmented examination requirements for post-tensioning system repair/replacement activities are in accordance with Table IWL-2521-2. Tendon anchorage and wires or strands are visually examined for cracks, corrosion, and mechanical damage. Tendon wires or strands are also tested for yield strength, ultimate tensile strength, and elongation. The tendon corrosion protection medium is tested by analysis for alkalinity, water content, and soluble ion concentrations. The pH of free water samples is analyzed.

4 ***Detection of Aging Effects:*** The frequency and scope of examinations specified in 10 CFR 50.55a (TN249) and Subsection IWL provide reasonable assurance that aging effects would be detected before they would compromise the design basis requirements. The frequency of inspection is specified in IWL-2400. Concrete inspections are performed in accordance with Examination Category L-A. Under Subsection IWL, inservice inspection (ISI) of concrete and unbonded post-tensioning systems is required 1, 3, and 5 years after the initial structural integrity test. Thereafter, inspections are performed at 5-year intervals. For sites with multiple plants, the schedule for ISI is provided in IWL-2421. In the case of tendons, only a sample of the tendons of each tendon type requires examination during each inspection.

The tendons to be examined during an inspection are selected on a random basis. Regarding detection methods for aging effects, all accessible concrete surfaces receive a General Visual examination (as defined by the ASME Code). Selected areas, such as those that indicate suspect conditions and concrete surface areas surrounding tendon anchorages (Category L-B), receive a more rigorous Detailed Visual examination (as defined by the ASME Code). Prestressing forces in sample tendons are measured. In addition, one sample tendon of each type is detensioned. A single wire or strand is removed from each detensioned tendon for examination and testing. These visual examination methods and testing would identify the aging effects of accessible concrete components and prestressing systems in concrete containments. Examination of the corrosion protection medium and free water is tested for each examined tendon as specified in Table IWL-2525-1.

5 ***Monitoring and Trending:*** Except in inaccessible areas, all concrete surfaces are monitored on a regular basis by virtue of the examination requirements. Inspection results are documented and compared to previous results to identify changes from prior inspections. Quantitative measurements and qualitative information are recorded and trended for findings exceeding the acceptance criteria described under Element 6 for all applicable parameters monitored or inspected. The use of photographs or surveys is recommended. Photography and its variations may be used to trend aging effects such as cracking, spalling, delamination, popouts, or other age-related concrete degradation as illustrated in ACI 201.1R. Photographic records may be used to document and trend the type, severity, extent, and progression of degradation.

For prestressed containments, trending of prestressing forces in tendons is required in accordance with the “acceptance by examination” criteria in IWL-3220. In addition to the random sampling used for tendon examination, one tendon of each type is selected from the first-year inspection sample and designated as a common tendon. Each common tendon is then examined during each inspection. Corrosion protection medium chemistry and free water pH are monitored for each examined tendon. This procedure provides monitoring and trending information over the life of the plant. 10 CFR 50.55a (TN249) and Subsection IWL also require that prestressing forces in all inspection sample tendons be measured by lift-off or equivalent tests and compared with acceptance standards based on the predicted force for that type of tendon over its life.

6 ***Acceptance Criteria:*** IWL-3000 provides acceptance standards for concrete containments. Quantitative acceptance criteria for concrete surfaces based on the “second-tier” evaluation criteria provided in Chapter 5 of ACI 349.3R are acceptable. Applicants who elect to use plant-specific criteria for concrete containment structures should describe the criteria and provide a technical basis for deviations from the criteria in ACI 349.3R. Inspection results, based on the acceptance criteria selected, are evaluated by the responsible engineer to ensure that the corrective action is implemented before loss of intended functions occurs.

The acceptance standards for the unbonded post-tensioning system are quantitative in nature. For the post-tensioning system, quantitative acceptance criteria are given for tendon force and elongation, tendon wire or strand samples, and corrosion protection medium. Free water in the tendon anchorage areas is not acceptable, as specified in IWL-3221.3. If free water is found, the recommendations in Table IWL-2525-1 are followed. 10 CFR 50.55a and Subsection IWL do not define the method for calculating predicted tendon prestressing forces for comparison to the measured tendon lift-off forces. The predicted tendon forces are calculated in accordance with RG 1.35.1, “Determining Prestressing Forces for Inspection of Prestressed Concrete Containments,” which provides an acceptable methodology for use through the subsequent period of extended operation.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Subsection IWL specifies that items for which examination results do not meet the acceptance standards are to be evaluated in accordance with IWL-3300, “Evaluation,” and described in an engineering evaluation report. The report is to include an evaluation of whether the concrete containment is acceptable without repair of the item and, if repair is required, the extent, method, and completion date of the repair or replacement. The report also identifies the cause of the condition and the extent, nature, and frequency of additional examinations. Subsection IWL also provides repair procedures to follow in IWL-4000. This includes requirements for the concrete repair, repair of reinforcing steel, and repair of the post-tensioning system.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

IWA-1400 specifies the preparation of plans, schedules, and ISI summary reports. In addition, written examination instructions and procedures, verification of qualification level of personnel who perform the examinations, and documentation of a QA program are specified. IWA-6000 specifically covers the preparation, submittal, and retention of records and reports.

10 ***Operating Experience:*** ASME Code Section XI, Subsection IWL was incorporated into 10 CFR 50.55a in 1996. Prior to that time, the prestressing tendon inspections were performed in accordance with the guidance provided in RG 1.35, “Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments.” Operating experience (OE) pertaining to degradation of reinforced concrete in concrete containments was gained through the inspections required by 10 CFR 50.55a(g)(4) (i.e., Subsection IWL), 10 CFR Part 50, Appendix J, and ad hoc inspections conducted by licensees and the NRC. NUREG–1522, “Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures,” described instances of cracked, spalled, and degraded concrete for reinforced and prestressed concrete containments. The NUREG also described cracked anchor heads for the prestressing tendons at three prestressed concrete containments. NRC Information Notice (IN) 99-10, Revision 1, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment,” described occurrences of degradation in prestressing systems. IN 2010-14, “Containment Concrete Surface Condition Examination Frequency and Acceptance Criteria,” described issues concerning the containment concrete surface condition examination frequency and acceptance criteria. The program considers the degradation concerns described in these generic communications. Implementation of Subsection IWL, in accordance with 10 CFR 50.55a, is a necessary element of aging management for concrete containments through the subsequent period of extended operation.

NRC Inspection Report 05000302/2009007 documents OE of an unprecedented delamination event that occurred during a major containment modification of a post-tensioned concrete containment. Although the event is not considered attributable to an aging mechanism, aging characteristics of prestressed concrete containments and lessons learned should be an important consideration for major containment modification repair/replacement activities, especially those involving significant detensioning and retensioning of tendons, during the subsequent period of extended operation.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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_____. ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWE, Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants.” New York, New York: The American Society of Mechanical Engineers. 2008.

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NRC. Information Notice 99-10, Revision 1, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment.” Revision 1. Agencywide Documents Access and Management System (ADAMS) Accession No. ML031500244. Washington DC: U.S. Nuclear Regulatory Commission. April 1999.

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_____. NUREG–1522, “Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1995.

[2] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

_____. Regulatory Guide 1.35.1, “Determining Prestressing Forces for Inspection of Prestressed Concrete Containments.” ADAMS Accession No. ML003740040. Washington, DC: U.S. Nuclear Regulatory Commission. July 1990.

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XI.S3 ASME SECTION XI, SUBSECTION IWF

Program Description

Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a, imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code),[1] Section XI, for Classes 1, 2, and 3, and metal containment (MC) piping and components and their associated supports. The ISI of supports for ASME piping and components is addressed in Section XI, Subsection IWF. This program supplements ASME Code, Section XI, Subsection IWF, which constitutes an existing mandated program applicable to managing the aging of ASME Classes 1, 2, 3, and MC component supports for subsequent license renewal.

The scope of inspection for supports is based on sampling of the total support population. The sample size varies depending on the ASME Class. The largest sample size is specified for the most critical supports (ASME Class 1). The sample size decreases for the less critical supports (ASME Classes 2 and 3). Discovery of support deficiencies during regularly scheduled inspections triggers an increase in the inspection scope. The primary inspection method employed is visual examination. Degradation that potentially compromises support function or load capacity is identified for evaluation. ASME Code Section XI, Subsection IWF specifies acceptance criteria and corrective actions. Supports requiring corrective actions are reexamined during the next inspection period.

The requirements of Subsection IWF are supplemented to include monitoring of high-strength bolting (actual measured yield strength greater than or equal to 150 kilo-pounds per square inch (ksi; 1,034 megapascals [MPa]) for cracking. This program emphasizes proper selection of bolting material, lubricants, and installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. This program includes a one-time inspection of additional supports for each group of materials used and the environments to which they are exposed outside of the existing Subsection IWF sample population.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program addresses ASME Class 1, 2, 3, and MC component supports. The scope of the program includes support members, structural bolting, high-strength structural bolting (actual measured yield strength greater than or equal to 150 ksi [1,034 MPa]), anchor bolts, welds, support anchorage to the building structure, accessible sliding surfaces, constant and variable load spring hangers, guides, stops, and vibration isolation elements. The acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) is evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation of such inaccessible areas.

2 ***Preventive Action:*** Operating experience and laboratory examinations show that the use of molybdenum disulfide (MoS_2) as a lubricant is a potential contributor to stress corrosion cracking (SCC), especially when applied to high-strength bolting. Thus, MoS_2 and other lubricants containing sulfur should not be used. Preventive measures also include using bolting material that has an actual measured yield strength of less than 150 ksi (1,034 MPa). Bolting replacement and maintenance activities include proper selection of bolting material

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

and lubricants, and appropriate installation torque or tension, as recommended in Electric Power Research Institute (EPRI) documents (e.g., EPRI NP-5067 and EPRI TR–104213), American Society for Testing and Materials (ASTM) standards, and American Institute of Steel Construction Specifications, as applicable. If bolting within the scope of the program consists of ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts, and the ASTM F3125 specification, which consolidates and replaces high-strength structural bolting standards), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” need to be used.

3 ***Parameters Monitored or Inspected:*** The parameters monitored or inspected include corrosion; cracking, deformation; misalignment of supports; missing, detached, or loosened support items; general structural condition of weld joints and weld connections to building structure for loss of integrity; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. Accessible areas of sliding surfaces are monitored for debris, dirt, or indications of excessive loss of material due to wear that could prevent or restrict sliding as intended in the design basis of the support. Elastomeric or polymeric vibration isolation elements are monitored for cracking, loss of material, and hardening. Bolting is monitored for corrosion, loss of integrity of bolted connections due to self-loosening, and material conditions that can affect structural integrity. Concrete around anchor bolts is monitored for degradation under the Structures Monitoring program. High-strength bolting (actual measured yield strength greater than or equal to 150 ksi [1,034 MPa]) in sizes greater than 1-inch nominal diameter (including ASTM A490 bolts and ASTM F2280 bolts) should be monitored for SCC.

4 ***Detection of Aging Effects:*** The program requires that a sample of ASME Class 1, 2, and 3 piping supports that are not exempt from examination and 100 percent of supports other than piping supports (Class 1, 2, 3, and MC) be examined as specified in Table IWF-2500-1. The sample size examined for ASME Class 1, 2, and 3 component supports is as specified in Table IWF-2500-1. The provisions of ASME Code Section XI, Subsection IWF are supplemented to include a one-time inspection of an additional 5 percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. The one-time inspection is conducted within 5 years prior to entering the subsequent period of extended operation. The additional supports are selected from the remaining population of IWF piping supports. However, the responsible engineer should ensure that the sample includes components that are most susceptible to age-related degradation (i.e., based on time in service, aggressive environment, etc.).

The extent, frequency, and methods of examination are designed to detect, evaluate, or repair age-related degradation before there is a loss of component support intended function. The VT-3 examination method specified by the program can reveal loss of material due to corrosion and wear, cracks, verification of clearances, settings, physical displacements, loose or missing parts, debris or dirt in accessible areas of the sliding surfaces, or loss of integrity at bolted connections. The VT-3 examination can also detect loss of material and cracking of elastomeric or polymeric vibration isolation elements. Elastomeric or polymeric vibration isolation elements should be felt to detect hardening if the vibration isolation function is suspect. IWF-3200 specifies that visual examinations that detect surface flaws that exceed acceptance criteria may be supplemented by either surface or volumetric examinations to determine the character of the flaw.

For all high-strength bolting (actual measured yield strength greater than or equal to 150 ksi [1,034 MPa]) in sizes greater than 1-inch nominal diameter (including ASTM A490 and equivalent ASTM F2280), volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, should be performed at least once per interval, in addition to the VT-3 examination, to detect cracking. The sample of high-strength bolts subject to volumetric examination should be determined on a plant-specific basis such that the program can provide reasonable assurance that SCC is not occurring for the entire population of high-strength bolts. This volumetric examination may be waived with plant-specific justification.

5 ***Monitoring and Trending:*** The ASME Class 1, 2, 3, and MC component supports are examined periodically, as specified in Table IWF-2500-1. As required by IWF-2420(a), the sequence of component support examinations established during the first inspection interval is repeated during each successive inspection interval, to the extent practical. Component supports whose examinations do not reveal unacceptable degradation are accepted for continued service. Verified changes in conditions from prior examination are recorded in accordance with IWA-6230. Component supports for which examinations reveal unacceptable conditions and that are accepted for continued service by corrective measures or repair/replacement activity are reexamined during the next inspection period. When the reexamined component support no longer requires additional corrective measures during the next inspection period, the inspection schedule may revert to its regularly scheduled inspection. Examinations that reveal indications that exceed the acceptance standards and require corrective measures are extended to include additional examinations in accordance with IWF-2430. If a component support does not exceed the acceptance standards of IWF-3400 but is repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

6 ***Acceptance Criteria:*** The acceptance standards for visual examination are specified in IWF-3400. IWF-3410(a) identifies the following conditions as being unacceptable:

- deformations or structural degradations of fasteners, springs, clamps, or other support items;
- missing, detached, or loosened support items, including bolts and nuts;
- arc strikes, weld spatter, paint, scoring, roughness, or general corrosion on close tolerance machined or sliding surfaces;
- improper hot or cold positions of spring supports and constant load supports;
- misalignment of supports; and
- improper clearances of guides and stops.

Other unacceptable conditions include:

- loss of material due to corrosion or wear;
- debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support;
- cracked or sheared bolts, including high-strength bolts, and anchors;
- loss of material, cracking, and hardening of elastomeric or polymeric vibration isolation elements that could reduce the vibration isolation function; and
- cracks.

The above conditions may be accepted if the technical basis for their acceptance is documented.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50 (TN249), Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Identification of unacceptable conditions triggers an expansion of the inspection scope, in accordance with IWF-2430, and reexamination of the supports requiring corrective actions during the next inspection period, in accordance with IWF-2420(b). In accordance with IWF-3122, supports containing unacceptable conditions are evaluated, tested, corrected before being returned to service. Corrective actions are delineated in IWF-3122.2. IWF-3122.3 provides an alternative for evaluation or testing to substantiate structural integrity and/or functionality.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience*:** Degradation of threaded bolting and fasteners has occurred as a result of boric acid corrosion, SCC, and fatigue loading (U.S. Nuclear Regulatory Commission [NRC] Inspection and Enforcement Bulletin [IEB] 82-02, "Degradation of Threaded Fasteners In the Reactor Coolant Pressure Boundary of PWR Plants," NRC Generic Letter 91-17, "Generic Safety Issue 79, Bolting Degradation of Failure in Nuclear Power Plants"). SCC has occurred in high-strength bolts used for nuclear steam supply system component supports (EPRI NP-5769). NRC Information Notice 2009-04 describes deviations in the supporting forces of mechanical constant supports, from code-allowable load deviation, due to age-related wear on the linkages and increased friction between the various moving parts and joints within the constant support, which can adversely affect the analyzed stresses of connected piping systems.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

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[2] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

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RCSC. “Specification for Structural Joints Using High-Strength Bolts.” Chicago, Illinois: Research Council on Structural Connections. August 2014.

XI.S4 10 CFR PART 50, APPENDIX J

Program Description

A typical primary reactor containment system consists of a containment structure (containment), and a number of electrical, mechanical, equipment hatch, and personnel air lock penetrations. As described in Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," (Appendix J), periodic containment leak rate tests are required to assure that (1) leakage through these containments or systems and components penetrating these containments does not exceed allowable leakage rates specified in the Technical Specifications (TSs), and (2) integrity of the containment structure is maintained during its service life.

This aging management program (AMP) credits the existing program required by 10 CFR Part 50, Appendix J, and augments it to ensure that all containment pressure-retaining components are managed for age-related degradation.

Appendix J provides two options—Option A and Option B—to meet the requirements of a containment leak rate test (LRT) program. Option A is prescriptive—all testing is performed on specified periodic intervals. Option B is a performance-based approach. The U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program" and Nuclear Energy Institute (NEI) 94-01, Industry Guideline for Implementing Performance-Based Option for 10 CFR Part 50, Appendix J, as approved by the NRC final safety evaluation for NEI 94-01, Revision 2-A and Revision 3-A, provide additional information regarding Option B. Three types of tests (A, B, or C) are performed under either Option A or Option B, or a mix as adopted by licensees on a voluntary basis.

Type A integrated leak rate tests determine the overall containment integrated leakage rate, at the calculated peak containment internal pressure related to the design basis loss of coolant accident. Type B (containment penetration leak rate) tests detect local leaks and measure leakage across each pressure-containing or leakage-limiting boundary of containment penetrations. Type C (containment isolation valve leak rate) tests detect local leaks and measure leakage across containment isolation valves installed in containment penetrations or lines penetrating the containment.

Appendix J requires a General Visual inspection of the accessible interior and exterior surfaces of the containment structures and components (SCs) to be performed prior to any Type A test and at periodic intervals between tests based on the performance of the containment system. The visual inspections required by American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Section XI, Subsections IWE and IWL are acceptable substitutes for the General Visual inspection. The purpose of the Appendix J general visual inspection is to uncover any evidence of structural deterioration that may affect the containment structure leakage integrity or the performance of the Type A test.

Evaluation and Technical Basis

1 ***Scope of Program:*** The scope of the containment LRT program includes the containment system and related systems and components penetrating the containment pressure-retaining or leakage-limiting boundary. The aging effects associated with containment pressure-retaining boundary components within the scope of subsequent license renewal and excluded from Type B or C Appendix J testing must still be managed. Other programs may be credited for managing the aging effects associated with these components, but the component and the proposed AMP should be clearly identified.

2 ***Preventive Action:*** The containment LRT program is a performance monitoring program with no specific preventive actions.

3 ***Parameters Monitored or Inspected:*** The monitored parameters are leakage rates through the containment shell, containment liner, penetrations, associated welds, access openings, and associated pressure boundary components.

4 ***Detection of Aging Effects:*** A containment LRT program is effective in detecting the leakage rates of the containment pressure boundary components, including seals and gaskets, and in identifying and correcting the sources of leakage. While the calculation of leakage rates and satisfactory performance of containment leak rate testing demonstrate the leakage integrity of the containment, it does not by itself provide information that would indicate that age-related degradation has initiated or that the capacity of the containment may have been reduced for other types of loading conditions. Such indication would be achieved with the implementation of acceptable containment inservice inspection (ISI) programs such as ASME Code Section XI, Subsection IWE (Generic Aging Lessons Learned for Subsequent License Renewal [GALL-SLR] Report AMP XI.S1), and ASME Code Section XI, Subsection IWL (GALL-SLR Report AMP XI.S2).

5 ***Monitoring and Trending:*** Because the containment LRT program is repeated periodically throughout the operating license period, the entire containment pressure boundary is monitored over time. The frequency of these tests depends on which option (A or B) is selected. With Option A, testing is performed on a regular fixed time interval as defined in Appendix J. In the case of Option B, acceptable performance in prior tests meeting leakage rate limits serves as a basis for adjusting the testing interval. For valves and penetrations, administrative leakage rate limits may be set lower than the regulatory acceptance criteria for early detection of age-related degradation.

6 ***Acceptance Criteria:*** Plant TSs define the regulatory acceptance criteria for leakage rate limits. The regulatory acceptance criteria meet the requirements as set forth in Appendix J, and are part of each plant's licensing basis.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

Corrective actions are taken in accordance with Appendix J and NEI 94-01. When leakage rates do not meet the acceptance criteria, an evaluation is performed to identify the cause of the unacceptable performance and appropriate corrective actions are taken.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** To date, the Appendix J containment LRT program, in conjunction with the containment ISI program, have been effective in preventing unacceptable leakage through the containment pressure boundary. Implementation of Option B for testing frequency must be consistent with plant-specific operating experience (OE).

NRC Information Notice 92-20, “Inadequate Local Leak Rate Testing,” describes OE of inadequate local leak rate testing of two-ply steel expansion bellows that were used on some piping penetrations.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR Part 50, Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.72, “Immediate Notification Requirements for Operating Nuclear Power Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.73, “Licensee Event Report System.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

ASME. ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWE, Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants.” New York, New York: The American Society of Mechanical Engineers. 2008[1].

_____. ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWL, Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants.” New York, New York: The American Society of Mechanical Engineers. 2008.

[1] GALL-SLR Report Chapter I, Table 1, identifies the ASME Code Section XI editions and addenda that are acceptable to use for this AMP.

NEI. NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J." Revision 2-A. Washington, DC: Nuclear Energy Institute. October 2008.

_____. NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J." Revision 3-A. Agencywide Documents Access and Management System (ADAMS) Accession No. ML12221A202. Washington, DC: Nuclear Energy Institute. July 2012.

NRC. "Final Safety Evaluation for Electric Power Research Institute (EPRI) Report No. 1009325, Revision 2, Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals." ADAMS Accession ML072970208. Washington, DC: U.S. Nuclear Regulatory Commission. August 2007.

_____. "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) 94-01, Revision 2, Industry Guideline for Implementing Performance-Based Option of 10 CFR, Part 50, Appendix J." ADAMS Accession No. ML081140105. Washington, DC: U.S. Nuclear Regulatory Commission. June 2008.

_____. Information Notice 92-20, "Inadequate Local Leak Rate Testing." ADAMS Accession No. ML031200473. Washington, DC: U.S. Nuclear Regulatory Commission. March 1992.

_____. Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program." Revision 0. ADAMS Accession No. ML003740058. Washington, DC: U.S. Nuclear Regulatory Commission. September 1995.

XI.S5 MASONRY WALLS

Program Description

The U.S. Nuclear Regulatory Commission (NRC) Inspection and Enforcement Bulletin (IEB) 80-11, “Masonry Wall Design,” and NRC Information Notice (IN) 87-67, “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11,” constitute an acceptable basis for a masonry wall aging management program (AMP). NRC IEB 80-11 required (1) the identification of masonry walls in close proximity to or having attachments from safety-related systems or components and (2) the evaluation of design adequacy and construction practice. NRC IN 87-67 recommended plant-specific condition monitoring of masonry walls and administrative controls to ensure that the evaluation basis developed in response to NRC IEB 80-11 is not invalidated by (1) deterioration of the masonry walls (e.g., new cracks not considered in the reevaluation), (2) physical plant changes such as installation of new safety-related systems or components in close proximity to masonry walls, or (3) reclassification of systems or components from nonsafety-related to safety-related, if appropriate evaluation is performed to account for such occurrences.

Important elements in the evaluation of many masonry walls during the NRC IEB 80-11 program included (1) installation of steel edge supports to provide a sound technical basis for boundary conditions used in seismic analysis and (2) installation of steel bracing to ensure stability or containment of unreinforced masonry walls during a seismic event. Consequently, in addition to the development of cracks in the masonry walls, loss of function of the structural steel supports and bracing would also invalidate the evaluation basis. The steel edge supports and steel bracings are considered component supports and aging effects are managed by the Structures Monitoring program (Generic Aging Lessons Learned for Subsequent License Renewal [GALL-SLR] Report AMP XI.S6).

The program consists of periodic visual inspection of masonry walls within the scope of subsequent license renewal (SLR) to detect loss of material and cracking of masonry units and mortar. The aging effects that could affect the intended function of a masonry wall or potentially invalidate its evaluation basis are entered into the corrective action process for further analysis, repair, or replacement.

Since the issuance of NRC IEB 80-11 and NRC IN 87-67, the NRC promulgated Title 10 of the *Code of Federal Regulations* (10 CFR) 50.65 (TN249), “Maintenance Rule.” For SLR, masonry walls may be inspected as part of GALL-SLR Report AMP XI.S6 conducted for the Maintenance Rule, if the 10 program elements described below are incorporated in GALL-SLR Report AMP XI.S6. The aging effects on masonry walls that are considered fire barriers are managed by GALL-SLR Report AMP XI.M26, “Fire Protection.”

Evaluation and Technical Basis

1 ***Scope of Program:*** The scope includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4 (TN4878). Masonry walls consist of solid or hollow concrete block, mortar, grout, steel bracing, reinforcing, and supports. The aging effects on masonry walls that are considered fire barriers are also managed by GALL-SLR Report AMP XI.M26, “Fire Protection,” as well by this program. Aging effects on the steel elements of masonry walls are managed by GALL-SLR Report AMP XI.S6.

2 ***Preventive Action:*** This is a condition monitoring program and no specific preventive actions are required.

3 ***Parameters Monitored or Inspected:*** The primary parameters monitored are potential shrinkage and/or separation, cracking of masonry walls, cracking or loss of material at the mortar joints and gaps between the supports and masonry walls that could affect the intended function or potentially invalidate its evaluation basis.

4 ***Detection of Aging Effects:*** Visual examination of the masonry walls by qualified inspection personnel is sufficient. In general, masonry walls are inspected every 5 years. Provisions exist for more frequent inspections in areas where significant loss of material, cracking, or other signs of degradation are observed to provide reasonable assurance that there is no loss of intended function between inspections. In addition, masonry walls that are fire barriers are visually inspected in accordance with GALL-SLR Report AMP XI.M26. Steel elements of masonry walls are visually inspected under the scope of GALL-SLR Report AMP XI.S6.

5 ***Monitoring and Trending:*** Condition monitoring for evidence of shrinkage and/or separation and cracking of masonry is achieved by periodic examination. Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components’ intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. Inspection results are documented and compared to previous inspections to identify changes or trends in the condition of masonry walls. Crack widths and lengths, and gaps between supports and masonry walls, that approach or exceed acceptance criteria are measured and assessed for trends. Degradation detected from monitoring is evaluated. The use of photographs or surveys is encouraged and photographic records may be used to document and trend the type, severity, extent and progression of degradation.

6 ***Acceptance Criteria:*** For each masonry wall, observed degradation (e.g., shrinkage and/or separation, cracking of masonry walls, cracking or loss of material at the mortar joints and gaps between the supports and masonry walls) is assessed against the evaluation basis to confirm that the degradation has not invalidated the original evaluation assumptions or affected the wall’s capability to perform its intended functions. Further evaluation is conducted to determine whether corrective action is required when the degradation is determined to affect the intended function of the wall or invalidate its evaluation basis. Degraded conditions that exceed the acceptance criteria and are accepted without repair or other corrective actions are technically justified or supported by engineering evaluation.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

If any projected inspection results will not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site’s corrective action program.

A corrective action option is to develop a new analysis or evaluation basis that accounts for the degraded condition of the wall (i.e., acceptance by further evaluation). Other alternatives include repairing or replacing the degraded wall.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50 (TN249), Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Since 1980, masonry walls that perform an intended function have been systematically identified through licensee programs in response to NRC IEB 80-11, NRC Generic Letter 87-02, and 10 CFR 50.48. NRC IN 87-67 documented lessons learned from the NRC IEB 80-11 program and provided recommendations for administrative controls and periodic inspection to provide reasonable assurance that the evaluation basis for each safety-significant masonry wall is maintained. NUREG–1522 documents instances of observed cracks and other deterioration of masonry-wall joints at nuclear power plants. Whether conducted as a standalone program or as a part of structures monitoring, a masonry wall AMP that incorporates the recommendations delineated in NRC IN 87-67 provides reasonable assurance that the intended functions of all masonry walls within the scope of license renewal are maintained for the subsequent period of extended operation.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.48, "Fire Protection." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 54.4, "Scope." Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 54-TN4878

NRC. Generic Letter 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46." Agencywide Documents Access and Management System (ADAMS) Accession No. ML031150371. Washington, DC: U.S. Nuclear Regulatory Commission. February 1987.

_____. IE Bulletin 80-11, “Masonry Wall Design.” Washington, DC: U.S. Nuclear Regulatory Commission. May 1980.

_____. Information Notice 87-67, “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11.” Washington, DC: U.S. Nuclear Regulatory Commission. December 1987.

_____. NUREG–1522, “Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures.” ADAMS Accession No. ML06510407. Washington, DC: U.S. Nuclear Regulatory Commission. June 1995.

XI.S6 STRUCTURES MONITORING

Program Description

Implementation of structures monitoring under Title 10 of the *Code of Federal Regulations* (10 CFR) 50.65 (the Maintenance Rule) is addressed in the U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.160, and Nuclear Management and Resources Council 93-01. These two documents and supplemental guidance herein provide guidance for development of licensee-specific programs to monitor the condition of structures and structural components within the scope of the license renewal rule, such that there is no loss of the intended function of structures or structural components.

The structures monitoring program consists primarily of periodic visual inspections by personnel qualified to monitor structures and components (SCs) for applicable aging effects from degradation mechanisms, such as those described in the American Concrete Institute (ACI) Standards 349.3R, ACI 201.1R, and Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11.

Identified aging effects are evaluated by qualified personnel using criteria derived from industry codes and standards contained in the plant current licensing bases, including ACI 349.3R, ACI 318, SEI/ASCE 11, and the American Institute of Steel Construction (AISC) specifications, as applicable.

The program includes preventive actions taken to ensure structural bolting integrity. The program also includes periodic sampling and testing of groundwater and the need to assess the impact of any changes in its chemistry on below-grade concrete structures.

Evaluation and Technical Basis

1. ***Scope of Program:*** The scope of the program includes all SCs, component supports, and structural commodities in the scope of license renewal that are not covered by other structural aging management programs (AMPs) (i.e., “ASME Section XI, Subsection IWE” [Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.S1]; “ASME Section XI, Subsection IWL” (GALL-SLR Report AMP XI.S2); “ASME Section XI, Subsection IWF” (GALL-SLR Report AMP XI.S3); “Masonry Walls” (GALL-SLR Report AMP XI.S5); and NRC RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” (GALL-SLR Report AMP XI.S7). The effects of aging on reinforced concrete structural fire barriers (walls, ceilings, and floors) are also managed by GALL-SLR Report AMP XI.M26, “Fire Protection,” as well as by this program.

   Examples of SCs and commodities in the scope of the program are concrete and steel structures, structural bolting, anchor bolts and embedments, component support members, steel edge supports and steel bracings associated with masonry walls, pipe whip restraints and jet impingement shields, transmission towers, panels and other enclosures, racks, sliding surfaces, sump and pool liners, electrical cable trays and conduits, trash racks associated with water-control structures, electrical duct banks, manholes, doors, penetration seals, seismic joint filler and other elastomeric materials, and tube tracks.

   If protective coatings are relied upon to manage the effects of aging for any structures included in the scope of this program, the program is to address protective coating monitoring and maintenance. Otherwise, coatings on structures within the scope of this program are inspected only as an indication of the condition of the underlying material.

The scope of this program includes periodic sampling and testing of groundwater. The scope may also include inspection of masonry walls and water-control structures if all the program elements of “Masonry Walls” (GALL-SLR Report AMP XI.S5) and “Inspection of Water-Control Structures Associated with Nuclear Power Plants” (GALL-SLR Report AMP XI.S7) are incorporated in the elements of this program.

2 ***Preventive Action:*** The Structures Monitoring program is primarily a condition monitoring program, but it includes preventive actions to provide reasonable assurance that structural bolting integrity is maintained, as discussed in Electric Power Research Institute (EPRI) documents (such as EPRI NP-5067 and TR-104213), American Society for Testing and Materials (ASTM) standards, and AISC specifications, as applicable. The preventive actions emphasize proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. If the structural bolting consists of ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts, and the ASTM F3125 specification, which consolidates and replaces high-strength structural bolting standards), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connection publication, “Specification for Structural Joints Using High-Strength Bolts,” need to be used.

3 ***Parameters Monitored or Inspected:*** For each structure/aging effect combination, the specific parameters monitored or inspected depend on the particular SC or commodity. Parameters monitored or inspected are commensurate with industry codes, standards, and guidelines and also consider industry and plant-specific operating experience (OE). ACI 349.3R and SEI/ASCE 11 provide an acceptable basis for selection of parameters to be monitored or inspected for concrete and steel structural elements and for steel liners, joints, coatings, and waterproofing membranes (if applicable).

For concrete structures, parameters monitored include loss of material, cracking, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation. Steel SCs are monitored for loss of material due to corrosion. Structural steel bracing and edge supports associated with masonry walls are inspected for deflection or distortion, loose bolts, and loss of material due to corrosion. Painted or coated areas are examined for signs of distress that could indicate degradation of the underlying material.

Bolting within the scope of the program is monitored for loss of material, loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. In addition, concrete around anchor bolts is monitored for degradation.

Accessible sliding surfaces are monitored for indication of significant loss of material due to wear or corrosion, and for accumulation of debris or dirt. Elastomeric vibration isolators, structural sealants, and seismic joint fillers are monitored for cracking, loss of material, and hardening. Groundwater chemistry (pH, chlorides, and sulfates) is monitored periodically to assess its impact, if any, on below-grade concrete structures. If through-wall leakage or groundwater infiltration is identified, leakage volumes and chemistry are monitored and trended for signs of concrete or steel reinforcement degradation.

If necessary for managing the settlement and erosion of porous concrete subfoundations, the continued functionality of a site dewatering system is monitored.

4 ***Detection of Aging Effects:*** Structures are monitored under this program using periodic visual inspection of each structure/aging effect combination by a qualified inspector to ensure that aging degradation will be detected and quantified before there is loss of a structure's intended function. It may be necessary to enhance or supplement visual inspections with nondestructive examination, destructive testing, and/or analytical methods, based on the conditions observed or the parameter being monitored. Visual inspection of elastomeric elements is supplemented by tactile inspection to detect hardening if the intended function is suspect. In addition, reinforced concrete structural fire barriers (walls, ceilings, and floors) are visually inspected in accordance with GALL-SLR Report AMP XI.M26.

The inspection frequency depends on the safety significance and the condition of the structure, as specified in NRC RG 1.160. In general, all structures are monitored on an interval not to exceed 5 years. The program includes provisions for more frequent inspections based on an evaluation of the observed degradation. The responsible engineer for this program evaluates groundwater chemistry that is sampled from a location that is representative of the groundwater in contact with structures within the scope of subsequent license renewal. This can be done on an interval not to exceed 5 years as long as the evaluation accounts for seasonal variations (e.g., quarterly monitoring every fifth year). Inspector qualifications should be consistent with industry guidelines and standards and guidelines for implementing the requirements of 10 CFR 50.65 (TN249). Qualifications of inspection and evaluation personnel specified in ACI 349.3R are acceptable for inspection of concrete structures.

Indications of groundwater infiltration or through-concrete leakage are assessed for aging effects. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the water.

The Structures Monitoring program addresses detection of aging affects for inaccessible, below-grade concrete structural elements. For plants with nonaggressive groundwater and soil (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm), the program recommends: (1) evaluating the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation of such inaccessible areas, and (2) examining representative samples of the exposed portions of the below-grade concrete, when excavated for any reason.

For plants with aggressive groundwater or soil (pH < 5.5, chlorides > 500 ppm, or sulfates > 1,500 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 concrete aging during the subsequent period of extended operation. The plant-specific AMP may include evaluations, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater or soil, on an interval not to exceed 5 years.

5 ***Monitoring and Trending:*** Results of periodic inspections are documented and compared to previous results to identify changes from prior inspections. Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. Quantitative measurements and qualitative information are recorded and trended for findings that exceed the acceptance criteria described under Element 6 for all applicable parameters monitored or inspected. The use of photographs or surveys is encouraged and photographic records may be used to document and trend the type, severity, extent, and progression of degradation.

Quantitative baseline inspection data should be established per the acceptance criteria described herein prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria specified herein are acceptable in lieu of performing a new baseline inspection.

6 ***Acceptance Criteria:*** Inspection results are evaluated by qualified engineering personnel based on acceptance criteria selected for each structure/aging effect to ensure that the need for corrective actions is identified before loss of intended functions occurs. The criteria are derived from applicable codes and standards that include, but are not limited to, ACI 349.3R, ACI 318, SEI/ASCE 11, or the relevant AISC specifications and consider industry and plant OE. The criteria are directed at the identification and evaluation of degradation that may affect the ability of the structure or component to perform its intended function. Justified quantitative acceptance criteria are used whenever applicable. Acceptance criteria for concrete surfaces based on the "second-tier" evaluation criteria provided in Chapter 5 of ACI 349.3R are acceptable. Applicants who elect to use plant-specific criteria for concrete structures should describe the criteria and provide a technical basis for deviations from those in ACI 349.3R. Loose bolts and nuts are not acceptable unless accepted by engineering evaluation. Structural sealants are acceptable if the observed loss of material, cracking, and hardening will not result in loss of sealing. Elastomeric vibration isolation elements are acceptable if there is no loss of material, cracking, or hardening that could lead to the reduction or loss of isolation function. Acceptance criteria for sliding surfaces are (1) no indications of excessive loss of material due to corrosion or wear and (2) no debris or dirt that could restrict or prevent sliding of the surfaces as required by design. The Structures Monitoring program is to contain sufficient detail about acceptance criteria to conclude that this program element is satisfied.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program. If any projected inspection results will not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's corrective action program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** NUREG–1522 documents the results of a survey sponsored in 1992 by the Office of Nuclear Reactor Regulation to obtain information about the types of distress in the concrete and steel SCs, the type of repairs performed, and the durability of the repairs. Licensees who responded to the survey reported cracking, scaling, and leaching of concrete structures. The degradation was attributed to drying shrinkage, freeze-thaw, and abrasion. The NUREG also describes the results of NRC staff inspections at six plants. The staff observed concrete degradation, corrosion of component support members and anchor bolts, cracks and other deterioration of masonry walls, and groundwater leakage and seepage into underground structures. Information Notice (IN) 2011-20 discusses an instance of groundwater infiltration leading to alkali-silica reaction degradation in below-grade concrete structures, while IN 2004-05 and IN 2006-13 discusses instances of through-wall water leakage from spent fuel pools. NUREG/CR–7111 provides a summary of aging effects of safety-related concrete structures. Many license renewal applicants have found it necessary to enhance their Structures Monitoring program to ensure that the aging effects of SCs in the scope of 10 CFR 54.4 (TN4878) are adequately managed during the subsequent period of extended operation. There is reasonable assurance that implementation of the Structures Monitoring program described above will be effective in managing the aging of the in-scope SC supports through the period of subsequent license renewal.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

10 CFR 54.4, “Scope.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 54-TN4878

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EPRI. EPRI NP-5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel." Volume 1: Large Bolt Manual, 1987; Volume 2: Small Bolts and Threaded Fasteners. Palo Alto, California: Electric Power Research Institute. 1990.

_____. EPRI TR–104213, "Bolted Joint Maintenance & Application Guide." Palo Alto, California: Electric Power Research Institute. December 1995.

NEI. NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Revision 4A. Agencywide Documents Access and Management System (ADAMS) Accession No. ML11116A198. Washington, DC: Nuclear Energy Institute. 2011.

NRC. Information Notice 2004-05, "Spent Fuel Pool Leakage to Onsite Groundwater." Washington, DC: U.S. Nuclear Regulatory Commission. March 2004.

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_____. Information Notice 2011-20, "Concrete Degradation by Alkali-Silica Reaction." Washington, DC: U.S. Nuclear Regulatory Commission. November 2011.

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RCSC. "Specification for Structural Joints Using High-Strength Bolts." Chicago, Illinois. Research Council on Structural Connections. August 2014.

XI.S7 INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

Program Description

This program describes an acceptable basis for developing an inservice inspection (ISI) and surveillance program for dams, slopes, canals, and other raw water-control structures associated with emergency cooling water systems or flood protection of nuclear power plants (NPPs). The program addresses age-related deterioration, degradation due to environmental conditions, and the effects of natural phenomena that may affect water-control structures. The program recognizes the importance of periodic monitoring and maintenance of water-control structures so that the consequences of age-related deterioration and degradation can be prevented or mitigated in a timely manner.

The U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” provides additional detailed guidance for an inspection program for water-control structures, including guidance on engineering data compilation, inspection activities, technical evaluation, inspection frequency, and the content of inspection reports. NRC RG 1.127 delineates current NRC practice in evaluating ISI programs for water-control structures.

An aging management program (AMP) addressing water-control structures, commensurate with the program elements described below, is expected regardless of whether a plant is committed to NRC RG 1.127. Aging management of water-control structures and components (SCs) may be included in “Structures Monitoring” (Generic Aging Lessons Learned for Subsequent License Renewal [GALL-SLR] Report AMP XI.S6)], but details pertaining to water-control structures, as described herein, should be explicitly incorporated and identified in GALL-SLR Report AMP XI.S6 program elements if this approach is taken.

The program elements evaluated below do not include inspection of dams. For dam inspection and maintenance, programs under the regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC) or the U.S. Army Corps of Engineers (USACE), continued through the subsequent period of extended operation, are adequate for the purpose of aging management. For programs not falling under the regulatory jurisdiction of FERC or the USACE the staff evaluates the effectiveness of the AMP based on its compatibility with the common practices of the FERC and USACE programs.

Evaluation and Technical Basis

1 ***Scope of Program:*** The scope includes raw water-control structures associated with emergency cooling water systems or flood protection of NPPs. The water-control structures included in the program are concrete structures, embankment structures, spillway structures and outlet works, reservoirs, cooling water channels and canals, flood protection walls and gates, and intake and discharge structures. The scope of the program also includes structural steel, structural bolting associated with water-control structures, steel or wood piles and sheeting required for the stability of embankments and channel slopes, and miscellaneous steel, such as sluice gates and trash racks.

If protective coatings are relied upon to manage the effects of aging on any structures included in the scope of this program, the program is to address protective coating monitoring and maintenance. Otherwise, coatings on structures within the scope of this program are inspected only as an indication of the condition of the underlying material.

2 ***Preventive Action:*** This is a condition monitoring program. The program is augmented to include preventive actions to provide reasonable assurance of structural bolting integrity, as discussed in Electric Power Research Institute (EPRI) documents (such as EPRI NP-5067 and TR-104213), American Society for Testing and Materials (ASTM) standards, and American Institute of Steel Construction (AISC) specifications, as applicable. The preventive actions emphasize proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. If the structural bolting consists of ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts, and the ASTM F3125 specification, which consolidates and replaces high-strength structural bolting standards), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” need to be used.

3 ***Parameters Monitored or Inspected:*** NRC RG 1.127 identifies parameters to be monitored and inspected for water-control structures.

Parameters to be monitored and inspected for concrete structures are those described in American Concrete Institute (ACI) 201.1R and ACI 349.3R. They include cracking, movements (e.g., settlement, heaving, and deflection), conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage.

Parameters to be monitored and inspected for earthen embankment structures include settlement, depressions, sink holes, slope stability (e.g., irregularities in alignment and variances from originally constructed slopes), seepage, proper functioning of drainage systems, and degradation of slope protection features. Parameters monitored for channels and canals include erosion or degradation that may impose constraints on the function of the cooling system and present a potential hazard to the safety of the plant. Submerged emergency canals (e.g., artificially dredged canals at the river bed or the bottom of the reservoir) are monitored for sedimentation, debris, or instability of slopes that may impair the function of the canals under extreme low-flow conditions.

Further details of parameters to be monitored and inspected for these and other water-control structures are specified in Section C of NRC RG 1.127.

Steel components are monitored for loss of material due to corrosion.

Painted or coated areas are examined for signs of distress that could indicate degradation of the underlying material.

Bolting within the scope of the program is monitored for loss of material, loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. In addition, concrete around anchor bolts is monitored for cracking.

Accessible sliding surfaces are monitored for indication of loss of material due to wear or corrosion, and accumulation of debris or dirt.

Wooden components are monitored for loss of material and change in material properties.

4 ***Detection of Aging Effects:*** Inspection of water-control structures is conducted under the direction of qualified engineers experienced in the investigation, design, construction, and operation of these types of facilities. Qualifications of inspection and evaluation personnel specified in ACI 349.3R are acceptable for reinforced concrete water-control structures. Visual inspections are primarily used to detect the degradation of water-control structures. In some cases, instruments have been installed to measure the behavior of water-control structures. Available records and readings of installed instruments are to be reviewed to detect any unusual performance or distress that may be indicative of degradation. Periodic inspections are to be performed at least once every 5 years. This interval has been shown to be adequate for detecting degradation of water-control structures before a loss of an intended function occurs. The program includes provisions for increased inspection frequency based on an evaluation of the observed degradation. The program also includes provisions for special inspections immediately following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, or intense local rainfalls. The responsible engineer for this program evaluates the chemistry of raw water and groundwater that are sampled from a location that is representative of the water in contact with structures within the scope of subsequent license renewal. This can be done on an interval not to exceed 5 years as long as the evaluation accounts for seasonal variations (e.g., quarterly monitoring every fifth year).

Indications of groundwater infiltration or through-concrete leakage are assessed for aging effects. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessments may include analysis of the leakage pH, along with the mineral, chloride, sulfate, and iron content in the water.

The program addresses detection of aging effects for inaccessible, below-grade, and submerged concrete structural elements. For plants that have nonaggressive raw water, groundwater, and soil (pH > 5.5, chlorides < 500 parts per million [ppm], and sulfates < 1,500 ppm), the program includes (1) evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation of such inaccessible areas; and (2) examination of representative samples of the exposed portions of the below-grade concrete when excavated for any reason. Submerged concrete structures may be inspected during periods of low tide or when dewatered. Plant-specific justification is provided in the subsequent license renewal application for the acceptability of submerged concrete if inspections do not occur within the 5-year interval. Areas covered by silt, vegetation, or marine growth are not considered inaccessible and are cleaned and inspected in accordance with the standard inspection frequency.

For plants that have aggressive raw water or groundwater or soil (pH < 5.5, chlorides > 500 ppm, or sulfates > 1,500 ppm) and/or where the structural elements have experienced degradation, a plant-specific AMP accounting for the extent of the degradation experienced is implemented to manage the effects of aging during the subsequent period of extended operation. The plant-specific AMP may include evaluations, destructive testing, and/or focused inspections of accessible (leading indicator) or below-grade, inaccessible structural elements exposed to aggressive raw water or groundwater or soil on an interval not to exceed 5 years, and submerged structural elements are visually inspected (e.g., dewatering, divers) at least once every 5 years.

5 ***Monitoring and Trending:*** Results of periodic inspections are documented and compared to previous results to identify changes from prior inspections. Where practical, identified degradation is projected until the next scheduled inspection occurs. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. Quantitative measurements and qualitative information are recorded and trended for findings exceeding the acceptance criteria described under Element 6 for all applicable parameters monitored or inspected. The use of photographs or surveys is encouraged, and photographic records may be used to document and trend the type, severity, extent and progression of degradation.

Quantitative baseline inspection data should be established per the acceptance criteria described herein prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria specified herein are acceptable in lieu of performing a new baseline inspection.

6 ***Acceptance Criteria:*** The quantitative "second-tier" evaluation criteria provided in Chapter 5 of ACI 349.3R are acceptable for concrete. Applicants who elect to use plant-specific criteria for concrete structures should describe the criteria and provide a technical basis for deviations from those in ACI 349.3R. Acceptance criteria for earthen structures, such as canals and embankments, are consistent with programs falling under the regulatory jurisdiction of the FERC or the USACE. Loose bolts and nuts, and degradation of piles and sheeting, are accepted by engineering evaluation or subject to corrective actions. Engineering evaluation is documented and based on codes, specifications, and standards such as AISC specifications, Structural Engineering Institute/American Society of Civil Engineers Standard 11-99, "Guideline for Structural Condition Assessment of Existing Buildings," and those referenced in the plant's current licensing basis.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant's corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

When inspection findings indicate that significant changes have occurred, the conditions are to be evaluated. This includes a technical assessment of the causes of distress or abnormal conditions, an evaluation of the behavior or movement of the structure, and recommendations for remedial or mitigating measures. If any projected inspection results will not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's corrective action program.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience:*** Degradation of water-control structures has been detected, through NRC RG 1.127 programs, at a number of nuclear power plants, and, in some cases, it has required remedial action. NRC NUREG–1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures," describes instances and corrective actions of severely degraded steel and concrete components at the intake structure and pump house of coastal plants. Other degradation described in the NUREG include appreciable leakage from the spillway gates, concrete cracking, corrosion of spillway bridge beam seats of a plant dam and cooling canal, and appreciable differential settlement of the outfall structure of another. No loss of intended functions has resulted from these occurrences. Therefore, it can be concluded that the inspections implemented in accordance with the guidance in NRC RG 1.127 have been successful in detecting significant degradation before loss of intended function occurs.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

ACI. ACI Standard 201.1R-08, “Guide for Conducting a Visual Inspection of Concrete in Service.” Farmington Hills, Michigan: American Concrete Institute. 2008.

_____. ACI Standard 349.3R-02, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.” Farmington Hills, Michigan: American Concrete Institute. 2002.

AISC. “AISC Specification for Steel Buildings.” Chicago, Illinois: American Institute of Steel Construction, Inc. 2010.

ASCE. SEI/ASCE 11-99, “Guideline for Structural Condition Assessment of Existing Buildings.” Reston, Virginia: American Society of Civil Engineers. 2000.

EPRI. EPRI NP-5067, “Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel.” Volume 1: Large Bolt Manual, 1987; Volume 2: Small Bolts and Threaded Fasteners. Palo Alto, California: Electric Power Research Institute. 1990.

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NRC. NUREG–1522, “Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML06510407. Washington, DC: U.S. Nuclear Regulatory Commission. June 1995.

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_____. Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” ADAMS Accession No. ML12216A016. Washington, DC: U.S. Nuclear Regulatory Commission. 1993.

RCSC. “Specification for Structural Joints Using High-Strength Bolts.” Chicago, Illinois: Research Council on Structural Connections. August 2014.

XI.S8 PROTECTIVE COATING MONITORING AND MAINTENANCE

Program Description

Proper maintenance of protective coatings inside containment (defined as Service Level I in the U.S. Nuclear Regulatory Commission [NRC] Regulatory Guide [RG] 1.54, Revision 1, or latest version) is essential to the operability of post-accident safety systems that rely on water recycled through the containment sump/drain system. Degradation of coatings can lead to clogging of emergency core cooling system (ECCS) suction strainers, which reduces flow through the system and could cause unacceptable head loss for the pumps.

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside containment (e.g., steel liner, steel containment shell, structural steel, supports, penetrations, and concrete walls and floors) also serves to prevent or minimize loss of material due to corrosion of carbon steel components and aids in decontamination. Regulatory Position C4 in NRC RG 1.54, Revision 3, describes an acceptable technical basis for a Service Level I coatings monitoring and maintenance program that can be credited for managing the effects of corrosion for carbon steel elements inside containment. ASTM International (formerly American Society for Testing and Materials) standard ASTM D 5163-08 and endorsed years of the standard in NRC RG 1.54 are acceptable and considered consistent with NUREG–2191. In addition, Electric Power Research Institute Report 1019157, “Guideline on Nuclear Safety-Related Coatings (December 2009),” provides additional information about the ASTM standard guidelines.

A comparable program for monitoring and maintaining protective coatings inside containment, developed in accordance with NRC RG 1.54, Revision 3, is acceptable as an aging management program (AMP) for subsequent license renewal (SLR).

Service Level I coatings credited for preventing corrosion of steel containments and steel liners for concrete containments are subject to requirements specified by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section XI, Subsection IWE (Generic Aging Lessons Learned for Subsequent Licensnse Reneweal [GALL-SLR] Report AMP XI.S1). However, this program (GALL-SLR Report AMP XI.S8) reviews Service Level I coatings to ensure that the protective coating monitoring and maintenance program is adequate for SLR.

Evaluation and Technical Basis

1 ***Scope of Program:*** The minimum scope of the program is Service Level I coatings applied to steel and concrete surfaces inside containment (e.g., steel liner, steel containment shell, structural steel, supports, penetrations, and concrete walls and floors), defined in NRC RG 1.54, Revision 3, as follows: “Service Level I coatings are used in areas inside the reactor containment where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown.” The scope of the program also should include any Service Level I coatings that are credited by the licensee for preventing loss of material due to corrosion in accordance with GALL-SLR Report AMP XI.S1.

2 ***Preventive Action:*** The program is a condition monitoring program and does not recommend any preventive actions. However, for plants that credit coatings to minimize loss of material, this program is a preventive action.

3 ***Parameters Monitored or Inspected:*** ASTM D-5163-08 provides guidelines that are acceptable to the NRC staff for establishing an inservice coatings monitoring program for

Service Level I coating systems in operating nuclear power plants, and identifies the parameters monitored or inspected to be “any visible defects, such as blistering, cracking, flaking, peeling, rusting, and physical damage.”

4 ***Detection of Aging Effects:*** General Visual inspections, as per ASTM D5163-08, will be performed on an interval not to exceed 6 years. The inspection interval will be based on station operating experience and trending of the total amount of degraded and unqualified coatings allowed in containment that demonstrates acceptable coating performance with respect to the ECCS sump strainer debris limits. ASTM D 5163-08, paragraph 9, discusses the qualifications for inspection personnel, the inspection coordinator, and the inspection results evaluator. ASTM D 5163-08, subparagraph 10.1, discusses development of the inspection plan and the inspection methods to be used. It states that a General Visual inspection shall be conducted on all readily accessible coated surfaces during a walk-through. After a walk-through, or during the General Visual inspection, thorough visual inspections shall be carried out on previously designated areas and on areas noted as being deficient during the walk-through. A thorough visual inspection shall also be carried out on all coatings near sumps or screens associated with the ECCS. This subparagraph also addresses field documentation of inspection results. ASTM D 5163-08, subparagraph 10.5, identifies instruments and equipment needed for inspection.

5 ***Monitoring and Trending:*** ASTM D 5163-08 identifies monitoring and trending activities in subparagraph 7.2, which specifies a pre-inspection review of the previous two monitoring reports, and in subparagraph 11.1.2, which specifies that the inspection report should prioritize repair areas as either needing repair during the same outage or as postponing repair to occur during future outages, but under surveillance in the interim period. The assessment derived from periodic inspections and analysis of total amount of degraded coatings in the containment is compared with the total amount of permitted degraded coatings to provide reasonable assurance of post-accident operability of the ECCS.

An applicant that proposes to extend the inspection interval to more often than every refueling outage will need to provide information regarding the available margin for its ECCS suction strainers to accommodate coatings debris. The applicant will also demonstrate that the ECCS suction strainer debris margin will be maintained for the length of the inspection intervals during the subsequent license renewal period given trending of degraded and unqualified coatings. Trending of degraded and unqualified coatings will be commensurate with the inspection interval (if more than every refueling outage). This may result in trending of inspection reports from more than the two previous monitoring reports noted above.

6 ***Acceptance Criteria:*** ASTM D 5163-08, subparagraphs 10.2.1 through 10.2.6, 10.3, and 10.4, contain one acceptable method for the characterization, documentation, and testing of defective or deficient coating surfaces. Additional ASTM and other recognized test methods are available for use in characterizing the severity of observed defects and deficiencies. The evaluation covers blistering, cracking, flaking, peeling, delamination, and rusting.
ASTM D 5163-08, paragraph 11, addresses evaluation. It specifies that the inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, and prioritization of repairs.

7 ***Corrective Actions:*** Results that do not meet the acceptance criteria are addressed in the applicant’s corrective action program under the specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

A recommended corrective action plan is required for major defective areas so that these areas can be repaired during the same outage, if appropriate.

8 ***Confirmation Process:*** The confirmation process is addressed through the specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

9 ***Administrative Controls:*** Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10 ***Operating Experience*:** NRC Information Notice 88-82, NRC Bulletin 96-03, NRC Generic Letter (GL) 04-02, and NRC GL 98-04 describe industry experience pertaining to coatings degradation inside containment and the consequential clogging of sump strainers. NRC RG 1.54, Revision 3, was issued in April 2017. Monitoring and maintenance of Service Level I coatings conducted in accordance with Regulatory Position C4 are expected to be an effective program for managing degradation of Service Level I coatings and, consequently, an effective means of managing the loss of material due to corrosion of carbon steel structural elements inside containment.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

ASTM. ASTM D 5163-05, “Guide for Establishing Procedures to Monitor the Performance of Coating Service Level I Coating Systems in an Operating Nuclear Power Plant.” West Conshohocken, Pennsylvania: American Society for Testing and Materials. 2005.

_____. ASTM D 5163-08, “Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants.” West Conshohocken, Pennsylvania*:* American Society for Testing and Materials. 2008.

_____. ASTM D 5163-96, “Standard Guide for Establishing Procedures to Monitor the Performance of Safety Related Coatings in an Operating Nuclear Power Plant.” West Conshohocken, Pennsylvania: American Society for Testing and Materials. 1996.

EPRI. EPRI 1003102, "Guideline on Nuclear Safety-Related Coatings." Revision 1. (Formerly TR-109937). Palo Alto, California: Electric Power Research Institute. November 2001.

_____. EPRI 1019157, "Guideline on Nuclear Safety-Related Coatings." Revision 2. (Formerly TR-109937and 1003102). Palo Alto, California: Electric Power Research Institute. December 2009.

NRC. Bulletin 96-03, "Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors." Washington, DC: U.S. Nuclear Regulatory Commission. May 1996.

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_____. Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment." Washington, DC: U.S. Nuclear Regulatory Commission. July 1998.

_____. Information Notice 88-82, "Torus Shells with Corrosion and Degraded Coatings in BWR Containments." Washington, DC: U.S. Nuclear Regulatory Commission. November 1988.

_____. Information Notice 97-13, "Deficient Conditions Associated With Protective Coatings at Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. March 1997.

_____. Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants." Revision 0. Washington, DC: U.S. Nuclear Regulatory Commission. June 1973.

_____. Regulatory Guide 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." Revision 1. Washington, DC: U.S. Nuclear Regulatory Commission. July 2000.

_____. Regulatory Guide 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." Revision 2. Washington, DC: U.S. Nuclear Regulatory Commission. October 2010.

_____. Regulatory Guide 1.54, "Service Level I, II, III, and In-Scope License Renewal Protective Coatings Applied to Nuclear Power Plants," Revision 3: Washington, DC: U.S. Nuclear Regulatory Commission. April 2017. ADAMS Accession No. ML17031A288.

1 **Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging**
2 **Management Programs**

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to Title 10 of the *Code of Federal Regulations* (10 CFR) 50.49 Environmental Qualification Requirements	This program applies to accessible electrical cable and connection electrical insulation material within the scope of license renewal subjected to an adverse localized environment. Accessible in-scope electrical cable and connection electrical insulation material is visually inspected and tested for cable and connection insulation surface anomalies indicating signs of reduced electrical insulation resistance. If visual inspections identify degraded or damaged conditions, then testing is performed for evaluation. Visual Inspection and testing may include thermography and one or more proven condition monitoring test methods applicable to the cable and connection insulation material. Electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in the applicant's procedures.	Program and subsequent license renewal (SLR) enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	This program applies to electrical cables and connections (cable system) electrical insulation material used in circuits with sensitive, high-voltage, low-level current signals within the scope of subsequent license renewal. Examples of these circuits include radiation monitoring and nuclear instrumentation that are subject to aging management review and subjected to adverse localized environments caused by temperature, radiation, or moisture. The program evaluates electrical insulation material for cables and connections subjected to an adverse localized environment at least once every 10 years.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49	This program applies to inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) medium-voltage power cable (operating voltage; 2 kV to 35 kV) within the	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
	Environmental Qualification Requirements	scope of license renewal exposed to significant moisture. This is a condition monitoring program. However, periodic actions are performed to prevent inaccessible cable from being exposed to significant moisture such as identifying and inspecting in-scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and draining the water, as needed. Significant moisture is defined as exposure to moisture that lasts more than 3 days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function. Submarine or other cables designed for continuous wetting or submergence are also included in this aging management program (AMP) as a one-time inspection and test with additional periodic tests and inspections determined by one-time inspection results and industry and plant-specific operating experience.	period of extended operation.
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	This program applies to inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) instrument and control cable, within the scope of license renewal exposed to significant moisture. This is a condition monitoring program. However, periodic actions are taken to prevent inaccessible instrumentation and control cable from being exposed to significant moisture, such as identifying and inspecting in-scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and draining the water, as needed. Significant moisture is defined as exposure to moisture that lasts more than 3 days (i.e., long-term wetting or submergence over a continuous period) that if left unmanaged,	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		could potentially lead to a loss of intended function.	
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	This program applies to inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) low-voltage power cable (operating voltage less than 2 kV) within the scope of license renewal exposed to significant moisture. This is a condition monitoring program. However, periodic actions are taken to prevent inaccessible low-voltage power cable from being exposed to significant moisture, such as identifying and inspecting in-scope accessible cable conduit ends and cable manholes/vaults for water accumulation, and draining the water, as needed. Significant moisture is defined as exposure to moisture that lasts more than 3 days (i.e., long-term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.E4	Metal Enclosed Bus	This program applies to metal enclosed bus (MEB) within the scope of SLR. The program is a condition monitoring program that uses sampling. The program requires the visual inspection of MEB internal surfaces to detect age-related degradation, including cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. MEB insulating material is visually inspected for signs of embrittlement, cracking, chipping, melting, swelling, discoloration, or surface contamination, which may indicate overheating or aging degradation. The internal bus insulating supports are visually inspected for structural integrity and signs of cracks. MEB external surfaces are visually inspected for loss of material due to general, pitting, and crevice corrosion. Accessible elastomers (e.g., gaskets, bolts, and sealants) are inspected for degradation, including surface cracking, crazing, scuffing, and changes in dimensions	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		(e.g., ballooning and necking), shrinkage, discoloration, hardening, and loss of strength. A sample of accessible bolted connections is inspected for increased resistance of connection by using thermography or by measuring connection resistance using a micro-ohmmeter. These inspections are performed at least once every 10 years.	
XI.E5	Fuse Holders	This program applies to fuse holders outside of active equipment within the scope of SLR and require age management activities. This is a condition monitoring program. The program uses visual inspection and testing to identify age-related degradation for both fuse holder electrical insulation material and fuse holder metallic clamps. The specific type of test performed is determined prior to the initial test and is to be a proven test for detecting increased resistance of connection of fuse holder metallic clamps, or other appropriate testing justified in the applicant's AMP.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	This program applies to electrical connections within the scope of SLR. The program is a condition monitoring program that consists of a representative sample of electrical connections tested prior to the subsequent period of extended operation, and the results are evaluated to determine the need for subsequent testing on a 10-year basis. The following factors are considered for sampling: voltage level (medium and low), circuit loading (high loading), connection type, and location (high temperature, high humidity, vibration, etc.). Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. Otherwise a technical justification of the methodology and sample size used for selecting components under the test should be included as part of the applicant's AMP documentation. The specific type of test to be performed is a proven test for detecting increased resistance of connection. As an alternative to thermography or resistance measurement of cable connections	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		for the accessible cable connections that are covered with electrical insulation materials such as tape, the applicant may perform visual inspection of the electrical insulation material to detect aging effects for covered cable connections. The basis for performing only a periodic visual inspection is documented.	
XI.E7	High-Voltage Insulators New AMP	This program was developed specifically to address aging management of in-scope high-voltage insulator aging mechanisms and effects. This is a condition monitoring program and manages the age-related degradation effects of within scope high-voltage insulators susceptible to airborne contaminates including dust, salt, fog, cooling tower plume, industrial effluent or loss of material.	The program is implemented 6 months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	This program consists of periodic volumetric, surface, and/or visual examination of American Society of Mechanical Engineers (ASME) Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, signs of degradation, and corrective actions. This program is in accordance with the ASME Code Section XI edition and addenda approved in accordance with provisions of 10 CFR 50.55a (TN249) during the subsequent period of extended operation.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.M2	Water Chemistry	This program mitigates the aging effects of loss of material due to corrosion, cracking due	The program is implemented

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		to stress corrosion cracking (SCC), and related mechanisms, and reduction of heat transfer due to fouling in components exposed to a treated water environment. Chemistry programs are used to control water chemistry for impurities (e.g., chloride, fluoride, and sulfate) that accelerate corrosion. This program relies on monitoring and control of water chemistry to keep peak levels of various contaminants below the system-specific limits, based on Electric Power Research Institute (EPRI) guidelines (1) Boiling Water Reactor Vessel and Internals Program (BWRVIP)-190 (EPRI 3002002623, BWR Water Chemistry Guidelines – 2014 Revision) for boiling water reactors (BWRs) or (2) EPRI 3002000505 (PWR Primary Water Chemistry – Revision 7) and EPRI 3002010645 (PWR Secondary Water Chemistry – Revision 8) for pressurized water reactors (PWRs).	6 months prior to the subsequent period of extended operation.
XI.M3	Reactor Head Closure Stud Bolting	This program includes (1) inservice inspection (ISI) in conformance with the requirements of the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, and (2) preventive measures to mitigate cracking. The program also relies on recommendations to address reactor head stud bolting degradation as delineated in U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.65, Revision 1. The program may use the bolting materials for closure studs with an ultimate tensile strength not exceeding 170 ksi as an alternative preventive measure.	The program is implemented 6 months prior to the subsequent period of extended operation.
XI.M4	BWR Vessel ID Attachment Welds	This program is a condition monitoring program that manages cracking in the reactor vessel inside diameter (ID) attachment welds. This program relies on visual examinations to detect cracking. The examination scope, frequencies, and methods are in accordance with ASME Code, Section XI, Table-IWB-2500-1, Examination Category B-N-2, and BWRVIP-48-A, “Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines,” dated November 2004. The scope of the examinations is expanded when flaws are detected. Any indications are evaluated in accordance with ASME Code, Section XI, or the guidance	The program is implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		in BWRVIP 48-A. Crack growth evaluations follow the guidance in BWRVIP-14-A, “Evaluation of Crack Growth in BWR Stainless Steel RPV Internals, dated September 2008; BWRVIP-59-A, “Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals,” dated May 2007; or BWRVIP-60-A, “BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals,” dated June 2003; as appropriate. The acceptance criteria are in BWRVIP-48-A and ASME Code, Section XI, Subarticle IWB-3520. Repair and replacement activities are conducted in accordance with BWRVIP-52-A, “Shroud Support and Vessel Bracket Repair Design Criteria,” dated September 2005.	
XI.M7	BWR Stress Corrosion Cracking	This program manages cracking due to intergranular stress corrosion cracking (IGSCC) for all BWR piping and piping welds made of austenitic stainless steel and nickel alloy that are 4 inches or larger in nominal diameter containing reactor coolant at a temperature above 93 °C (200 °F) during power operation, regardless of code classification. The program performs volumetric examinations to detect and manage IGSCC in accordance with NRC Generic Letter (GL) 88-01. Modifications to the extent and schedule of inspection in GL 88-01 are allowed in accordance with the inspection guidance in staff-approved BWRVIP-75-A. This program relies on the staff-approved positions that are described in NUREG–0313, Revision 2, and GL 88-01 and its Supplement 1 regarding selection of IGSCC-resistant materials, solution heat treatment and stress improvement processes, water chemistry, weld overlay reinforcement, partial replacement, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting requirements.	The program is implemented 6 months prior to the subsequent period of extended operation.
XI.M8	BWR Penetrations	This program includes BWR instrumentation penetrations, control rod drive (CRD) housing and incore-monitoring housing (ICMH)	The program is implemented 6 months prior to

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		penetrations, and standby liquid control nozzles/Core ΔP nozzles. The program manages cracking due to cyclic loading or stress corrosion cracking (SCC) by performing inspection and flaw evaluation in accordance with the guidelines of staff-approved BWRVIP-49-A, BWRVIP-47-A and BWRVIP-27-A and the requirements in the ASME Code, Section XI. The examination categories include volumetric examination methods (ultrasonic testing or radiography testing), surface examination methods (liquid penetrant testing or magnetic particle testing), and visual examination methods.	the subsequent period of extended operation.
XI.M9	BWR Vessel Internals	This program includes inspections and flaw evaluations in conformance with the guidelines of applicable staff-approved BWRVIP documents, and provides reasonable assurance of the long-term integrity and safe operation of BWR vessel internal components that are fabricated of nickel alloy and stainless steel (including martensitic stainless steel, cast stainless steel and associated welds). The program manages the effects of cracking due to SCC, IGSCC, or irradiation-assisted stress corrosion cracking (IASCC), cracking due to cyclic loading (including flow-induced vibration), loss of material due to wear, loss of fracture toughness due to neutron or thermal embrittlement, and loss of preload due to thermal or irradiation-enhanced stress relaxation. The program performs inspections for cracking and loss of material in accordance with the guidelines of applicable staff-approved BWRVIP documents and the requirements of ASME Code, Section XI, Table IWB 2500-1. The impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components. This program also manages loss of preload for core plate rim holddown bolts and jet pump assembly holddown beam bolts by performing visual inspections or stress analyses for adequate structural integrity.	The program is implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		This program performs evaluations to determine whether supplemental inspections in addition to the existing BWRVIP examination guidelines are necessary to adequately manage loss of fracture toughness due to thermal or neutron embrittlement and cracking due to IASCC for the subsequent period of extended operation. If the evaluations determine that supplemental inspections are necessary for certain components based on neutron fluence, cracking susceptibility and fracture toughness, the program conducts the supplemental inspections for adequate aging management.	
XI.M10	Boric Acid Corrosion	This program relies, in part, on the response to NRC GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," to identify, evaluate, and correct borated water leaks that could cause corrosion damage to reactor coolant pressure boundary components. The program also includes inspections, evaluations, and corrective actions for all components subject to aging management review that may be adversely affected by some form of borated water leakage. This program includes provisions to initiate evaluations and assessments when leakage is discovered by activities not associated with the program. This program follows the guidance described in Section 7 of WCAP-15988-NP, Revision 2, "Generic Guidance for an Effective Boric Inspection Program for Pressurized Water Reactors."	The program is implemented 6 months prior to the subsequent period of extended operation.
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)	This program addresses operating experience of degradation due to primary water stress corrosion cracking (PWSCC) of components or welds constructed from certain nickel alloys (e.g., Alloy 600/82/182) and exposed to PWR primary coolant at elevated temperature. The scope of this program includes the following groups of components and materials: (1) all nickel alloy components and welds that are identified in EPRI Materials Reliability Program (MRP)-126; (2) nickel alloy components and welds identified in ASME Code Cases N-770, N-729, and N-722, as incorporated by reference in 10 CFR 50.55a (TN249); and	The program is implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		(3) components that are susceptible to corrosion by boric acid and may be affected by leakage of boric acid from nearby or adjacent nickel alloy components previously described. This program is used in conjunction with GALL-SLR Report AMP XI.M2, "Water Chemistry" because water chemistry can affect the cracking of nickel alloys. The completeness of the plant's EPRI MRP-126 program is also verified prior to entering the subsequent period of extended operation. For nickel alloy components and welds addressed by the regulatory requirements of 10 CFR 50.55a, inspections are conducted in accordance with 10 CFR 50.55a. Other nickel alloy components and welds within the scope of this program are inspected in accordance with EPRI MRP-126.	
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	This program consists of the determination of the susceptibility potential significance of loss of fracture toughness due to thermal aging embrittlement of CASS piping and piping components in both the BWR and PWR reactor coolant pressure boundaries in regard to thermal aging embrittlement based on the casting method, molybdenum content, nickel content, and ferrite percentage. For potentially susceptible piping and piping components aging management is accomplished either through enhanced volumetric examination, enhanced visual examination, or a component-specific flaw tolerance evaluation.	The program is implemented 6 months prior to the subsequent period of extended operation.
XI.M16A	PWR Vessel Internals	This program relies on implementation of the inspection and evaluation guidelines in EPRI Technical Report (TR) No. 3002017168 (MRP-227, Revision 1-A) and EPRI TR No. 3002010399 (MRP-228, Revision 3) to manage the aging effects on the reactor vessel internal components, as supplemented by a gap analysis that identifies enhancements to the program that are needed to address an 80-year operating period. Alternatively, the program relies on implementation of an acceptable generic report such as an approved revision of MRP-227 that considers an operating period of 80 years.	The program, accounting for the impacts of a gap analysis, is implemented 6 months prior to the subsequent period of extended operation, or alternatively, a plant-specific program may be implemented 6 months prior to the subsequent

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		This program is used to manage (1) cracking due to SCC, PWSCC, IASCC, and cracking due to fatigue/cyclical loading; (2) loss of material due to wear; (3) loss of fracture toughness due to either thermal aging, neutron irradiation embrittlement, or void swelling; (4) dimensional changes due to void swelling or distortion; and (5) loss of preload due to thermal and irradiation enhanced stress relaxation or creep. [The applicant is to provide additional details to describe the gap analysis associated with the AMP.]	period of extended operation.
XI.M17	Flow-Accelerated Corrosion (FAC)	This program is based on the response to NRC GL 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," and relies on implementation of the EPRI guidelines in the Nuclear Safety Analysis Center 202L [(as applicable) Revision 2, 3, or 4], "Recommendations for an Effective Flow Accelerated Corrosion Program." The program includes the use of predictive analytical software [(as applicable) CHECWORKS™, BRT CICERO™, COMSY]. [(If applicable) This program also manages wall thinning caused by mechanisms other than FAC, in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms.] This program includes (1) identifying all susceptible piping systems and components; (2) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (3) performing analyses of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (4) inspecting components; (5) evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (6) incorporating inspection data to refine FAC models.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.M18	Bolting Integrity	This program focuses on closure bolting for pressure-retaining components and relies on	Program and SLR enhancements,

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		recommendations for a comprehensive bolting integrity program, as delineated in NUREG–1339 and EPRI NP–5769, with the exceptions noted in NUREG–1339 for safety-related bolting. The program also relies on industry recommendations for comprehensive bolting maintenance, as delineated in the EPRI 1015336 and 1015337. The program includes periodic visual inspection of closure bolting for indications of loss of preload, cracking, and loss of material due to general, pitting, and crevice corrosion, microbiologically influenced corrosion, and wear as evidenced by leakage. Closure bolting that is submerged, or where the piping systems contains air or gas for which leakage is difficult to detect, is inspected or tested by alternative means. The program also includes sampling-based volumetric examinations of high-strength closure bolting to detect indications of cracking. The program also includes preventive measures to preclude or minimize loss of preload and cracking. A related AMP XI.M1, "ASME Section XI Inservice Inspection (ISI) Subsections IWB, IWC, and IWD," includes inspections of safety-related and nonsafety-related closure bolting and supplements this bolting integrity program. Other related programs, AMPs XI.S1, "ASME Section XI, Subsection IWE"; XI.S3, "ASME Section XI Subsection IWF"; XI.S6, "Structures Monitoring"; XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plant"; and XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," manage the inspection of safety-related and nonsafety-related structural bolting.	when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.M19	Steam Generators	This program manages the aging of steam generator tubes, plugs, sleeves, divider plate assemblies(as applicable), tube-to-tubesheet welds, heads (interior surfaces of channel or lower/upper heads), tubesheets (primary side), and secondary side components that are contained within the steam generator. This program consists of aging management activities for the steam generator tubes, plugs,	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		sleeves, and secondary side components that are contained within the steam generator in accordance with the plant technical specifications and includes commitments to Nuclear Energy Institute (NEI) 97-06, Revision 3 and the associated EPRI guidelines. This program also performs General Visual inspections of the steam generator heads (internal surfaces) looking for evidence of cracking or loss of material (e.g., rust stains) at least every 72 effective full power months. These inspections may be performed every 96 effective full power months for units with technical specifications that allow for extended steam generator inspection intervals. The program includes foreign material exclusion as a means of inhibiting wear degradation, and secondary side maintenance activities, such as sludge lancing, for removing deposits that may contribute to component degradation. The program performs volumetric examination of steam generator tubes in accordance with the requirements in the technical specifications to detect aging effects if they occur. The technical specifications require condition monitoring (explicitly) and operational assessments (implicitly) to be performed to ensure that the tube integrity will be maintained until the next inspection.	
XI.M20	Open-Cycle Cooling Water System	This program relies, in part, on implementing the response to NRC GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” [(if applicable) and includes nonsafety-related portions of the open-cycle cooling water system]. The program includes (1) surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, (2) tests to verify heat transfer of heat exchangers, and (3) routine inspection and maintenance so that corrosion, erosion, protective coating failure, fouling, and biofouling cannot degrade the performance of systems serviced by the open-cycle cooling water system. This program includes enhancements to the guidance in NRC GL 89-13 that address operating experience such that aging effects are adequately managed.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
XI.M21A	Closed Treated Water Systems	This is a mitigation program that also includes a condition monitoring program to verify the effectiveness of the mitigation activities. The program consists of (1) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the effects of corrosion are minimized; (2) chemical testing of the water so that the water treatment program maintains the water chemistry within acceptable guidelines; and (3) inspections to determine the presence or extent of degradation. The program uses as applicable, EPRI 3002000590, “Closed Cooling Water Chemistry Guideline,” and includes corrosion coupon testing and microbiological testing.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.M22	Boraflex Monitoring	This program consists of (1) neutron attenuation testing (“blackness testing”) to determine gap formation, (2) sampling for the presence of silica in the spent fuel pool along with boron loss, and (3) monitoring and analysis of criticality to assure that the required 5% subcriticality margin is maintained. This program is implemented in response to NRC GL 96-04.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.M23	Inspection of Overhead Heavy Load and Light Load Handling Related to Refueling) Handling Systems	This program evaluates the effectiveness of maintenance monitoring activities for cranes and hoists. The program includes periodic visual inspections to detect loss of material due to corrosion, wear, cracking, and indications of loss of preload for load handling bridges, structural members, structural components and bolted connections. This program relies on the guidance in NUREG–0612, ASME B30.2, and other appropriate standards in the ASME B30 series. These cranes must also comply with the maintenance rule requirements provided in 10 CFR 50.65 (TN249).	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.M24	Compressed Air Monitoring	This program consists of monitoring moisture content and corrosion, and performance of the compressed air system, including (1) preventive monitoring of water (moisture), and other contaminants to keep within the specified limits and (2) inspection of components for indications of loss of material due to corrosion. This program is in response to NRC GL 88-14 and the Institute of Nuclear	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		Power Operations' Significant Operating Experience Report 88-01. It also relies on guidance from the ASME operations and maintenance standards and guides (ASME OM-S/G-2012, Division 2, Part 28) and American National standards Institute/International Society of Automation (ANSI/ISA)~~-S~~7.0.1-1996, and EPRI TR–10847 for testing and monitoring air quality and moisture. Additionally, periodic opportunistic visual inspections of component internal surfaces are performed to detect signs of loss of material due to corrosion.	
XI.M25	BWR Reactor Water Cleanup System	This program includes ISI and monitoring and control of reactor coolant water chemistry. Related to the inspection guidelines for the reactor water cleanup (RWCU) inspections of RWCU piping welds that are located outboard of the second containment isolation valve, the program includes measures delineated in the guidelines of NUREG–0313, Revision 2, and NRC GL 88-01, GL 88-01 Supplement 1, and any applicable NRC-approved alternatives to these guidelines and ISI in conformance with the ASME Code Section XI.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.M26	Fire Protection	This program includes fire barrier inspections. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, fire damper housings, and periodic visual inspection and functional tests of fire-rated doors so that their operability is maintained. The program also includes periodic inspection and testing of halon/carbon dioxide or clean agent fire suppression systems.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.M27	Fire Water System	This program is a condition monitoring program that manages aging effects associated with water-based fire protection system components. This program manages loss of material, cracking, and flow blockage due to fouling by conducting periodic visual inspections, tests, and flushes performed in accordance with the 2011 Edition of National Fire Protection Association Code 25 (NFPA 25). Testing or replacement of sprinklers that have been in place for 50 years is performed in accordance with NFPA 25. In	The program is implemented and inspections or tests begin within the 5-year period before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		addition to NFPA codes and standards, portions of the water-based fire protection system that are (1) normally dry but periodically subjected to flow and (2) cannot be drained or allow water to collect, are subjected to augmented testing beyond that specified in NFPA 25. The augmented testing includes (1) periodic system full flow tests at the design pressure and flow rate or internal visual inspections and (2) piping volumetric wall-thickness examinations. The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated. Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of sufficient organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed and the source is detected and corrected. Inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes for an adequate examination.	period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks	This program is a condition monitoring program that manages aging effects associated with outdoor tanks sited on soil or concrete, indoor large-volume tanks containing water designed with internal pressures approximating atmospheric pressure that are sited on concrete or soil, and other indoor tanks that sit on, or are embedded in concrete, where plant-specific operating experience indicates that the tank surfaces are periodically exposed to moisture, including the [applicant to list the specific tanks that are in the program scope]. The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice. Sealant or caulking is used for outdoor tanks at the concrete-component interface.	The program is implemented and inspections or tests begin within the 10-year period before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		This program manages loss of material and cracking by conducting periodic internal and external visual and surface examinations. Inspections of caulking or sealant are supplemented with physical manipulation. Surface exams are conducted to detect cracking when susceptible materials are used. [The applicant can modify this sentence if it is demonstrated that any in-scope stainless steel or aluminum tanks are not susceptible to SCC or loss of material based on the results of the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plant (SRP-SLR) Sections 3.1.2.2.16, 3.2.2.2.4, 3.3.2.2.3, 3.4.2.2.2, 3.2.2.2.2, 3.3.2.2.4, 3.4.2.2.3, 3.2.2.2.8, 3.3.2.2.8, 3.4.2.2.7, 3.2.2.2.10, 3.3.2.2.10, and 3.4.2.2.9.] Thickness measurements of tank bottoms are conducted to detect degradation. The external surfaces of insulated tanks are periodically sampling-based inspected. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.	refueling outage prior to the subsequent period of extended operation.
XI.M30	Fuel Oil Chemistry	This program relies on a combination of surveillance and maintenance procedures. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the plant's technical specifications. Guidelines of the ASTM Standards, such as ASTM D 0975, D 1796, D 2276, D 2709, D 6217, and D 4057, also may be used. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic cleaning/draining of tanks and by verifying the quality of new oil before its introduction into the storage tanks.	The program is implemented and inspections begin within the 10-year period before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
			prior to the subsequent period of extended operation.
XI.M31	Reactor Vessel Material Surveillance	This program requires implementation of a reactor vessel material surveillance program to monitor the changes in fracture toughness for the ferritic reactor vessel beltline materials, which are projected to receive a peak neutron fluence at the end of the design life of the vessel exceeding 10^{17} n/cm^2 (E >1 MeV). The surveillance capsules must be located near the inside vessel wall in the beltline region so that the material specimens duplicate, to the greatest degree possible, the neutron spectrum, temperature history, and maximum neutron fluence experienced at the reactor vessel's inner surface. Because of the resulting lead factors, surveillance capsules receive equivalent neutron fluence exposures earlier than the inner surface of the reactor vessel. This allows surveillance capsules to be withdrawn prior to the inner surface receiving an equivalent neutron fluence and therefore test results may bound the corresponding operating period in the capsule withdrawal schedule. This surveillance program must comply with ASTM International (formerly American Society for Testing and Materials) Standard Practice E 185-82, as incorporated by reference in 10 CFR Part 50, Appendix H. Because the withdrawal schedule in Table 1 of ASTM E 185-82 is based on plant operation during the original 40-year initial license term, standby capsules may need to be incorporated into the Appendix H program for appropriate monitoring during the subsequent period of extended operation. Surveillance capsules are designed and located to permit insertion of replacement capsules. If standby capsules will be incorporated into the Appendix H program for the subsequent period of extended operation and have been removed from the reactor vessel, the should be reinserted so that appropriate lead factors are maintained and test results will bound the corresponding operating period. This program includes	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation. This program includes removal and testing of at least one capsule during the subsequent period of extended operation, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		removal and testing of at least one capsule during the subsequent period of extended operation, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation. As an alternative to a plant-specific surveillance program complying with ASTM E 185-82, an integrated surveillance program (ISP) may be considered for a set of reactors that have similar design and operating features, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.C. The plant-specific implementation of the ISP is consistent with the latest version of the ISP plan that has received approval by the NRC for the subsequent period of extended operation. The objective of this Reactor Vessel Material Surveillance program is to provide sufficient material data and dosimetry to (1) monitor irradiation embrittlement to neutron fluences greater than the projected neutron fluence at the end of the subsequent period of operation, and (2) provide adequate dosimetry monitoring during the operational period. If surveillance capsules are not withdrawn during the subsequent period of extended operation, provisions are made to perform dosimetry monitoring. This program is a condition monitoring program that measures the increase in Charpy V-notch 30 ft-lb transition temperature and the drop in the upper-shelf energy as a function of neutron fluence and irradiation temperature. The data from this surveillance program are used to monitor neutron irradiation embrittlement of the reactor vessel, and are inputs to the neutron embrittlement time-limited aging analyses described in Section 4.2 of the SRP-SLR. The Reactor Vessel Material Surveillance program is also used in conjunction with AMP X.M2, “Neutron Fluence Monitoring,” which monitors neutron fluence for reactor vessel components and reactor vessel internal components.	

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		In accordance with 10 CFR Part 50 (TN249), Appendix H, all surveillance capsules, including those previously removed from the reactor vessel, must meet the test procedures and reporting requirements of ASTM E 185-82, to the extent practicable, for the configuration of the specimens in the capsule. Any changes in the capsule withdrawal schedule, including the conversion of standby capsules into the Appendix H program and extension of the surveillance program for the subsequent period of extended operation, must be approved by the NRC prior to their implementation, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3. Standby capsules placed in storage (e.g., removed from the reactor vessel) are maintained for possible future insertion.	
XI.M32	One-Time Inspection	This program is a condition monitoring program consisting of a one-time inspection of selected components to verify (1) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the subsequent period of extended operation; (2) the insignificance of an aging effect; and (3) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action. The elements of the program include (1) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended	The program is implemented and inspections begin within the period before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation. Structures and components should be inspected only after an incubation period of sufficient

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		function before the end of the subsequent period of extended operation. Periodic inspections are used (instead of this program) for structures or components with known age-related degradation mechanisms or when the environment in the subsequent period of extended operation is not expected to be equivalent to that in the prior operating period. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.	length that the inspection results provide reasonable confidence that the effects of aging will not affect the component's or structure's intended function during the subsequent period of extended operation.
XI.M33	Selective Leaching	This program is a condition monitoring program that includes a one-time inspection for components exposed to a closed-cycle cooling water or treated water environment when plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections are conducted for raw water, waste water, soil, and groundwater environments, and for closed-cycle cooling water and treated water environments when plant-specific operating experience has revealed selective leaching in these environments. Visual inspections coupled with mechanical examination techniques such as chipping or scraping are conducted. Periodic destructive examinations of components for physical properties (i.e., degree of dealloying, depth of dealloying, through-wall thickness, and chemical composition) are conducted for components exposed to raw water, waste water, soil, and groundwater environments, or for closed-cycle cooling water and treated water environments when plant-specific operating experience has revealed selective leaching in these environments. Inspections and tests are conducted to determine whether loss of material will affect the ability of the components to perform their intended function for the subsequent period of extended operation. Inspections are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface	The program is implemented and inspections begin within the 10-year period before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		conditions. When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the subsequent period of extended operation, additional inspections are performed.	
XI.M35	ASME Code Class 1 Small Bore-Piping	This program augments the existing ASME Code, Section XI requirements and is applicable to small-bore ASME Code Class 1 piping and systems with a nominal pipe size (NPS) diameter less than 4 inches and greater than or equal to 1 inch (1 ≤ NPS <4). This program provides a one-time volumetric inspection of a sample of this Class 1 piping. This program includes pipes and full and partial penetration (socket) welds. The program includes measures to verify that degradation is not occurring, thereby either confirming that there is no need to manage aging-related degradation or validating the effectiveness of any existing program for the subsequent period of extended operation. The one-time inspection program for ASME Code Class 1 small-bore piping includes locations that are susceptible to cracking. This program is applicable to systems that have not experienced cracking of ASME Code Class 1 small-bore piping. This program can also be used for systems that experienced cracking but have implemented design changes to effectively mitigate cracking. [Measure of effectiveness includes (1) the one-time inspection sampling is statistically significant; (2) samples will be selected as described in Element 5; and (3) no repeated failures over an extended period of time.] For systems that have experienced cracking and for which operating experience indicates design changes have not been implemented to effectively mitigate cracking, periodic inspection is proposed, as managed by a plant-specific AMP. If evidence of cracking is revealed by a one-time inspection, a periodic inspection is also proposed, as managed by a plant-specific AMP.	The program is implemented and inspections are completed within 6 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
XI.M36	External Surfaces Monitoring of	This program is a condition monitoring program that manages the loss of material, cracking, changes in material properties (of cementitious components), hardening or loss	Program and SLR enhancements, when applicable, are implemented

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
	Mechanical Components	of strength (of elastomeric components), and reduced thermal insulation resistance. Periodic visual inspections, not to exceed a refueling outage interval, of metallic, polymeric, insulation jacketing (insulation when not jacketed), and cementitious components are conducted. Surface examinations or ASME Code Section XI VT-1 examinations are conducted to detect cracking of stainless steel and aluminum components. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this program. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point) are periodically inspected every 10 years during the subsequent period of extended operation. [The applicant can modify this sentence if it is demonstrated that any in-scope stainless steel or aluminum components are not susceptible to SCC or loss of material based on the results of SRP-SLR Sections 3.1.2.2.16, 3.2.2.2.4, 3.3.2.2.3, 3.4.2.2.2, 3.2.2.2.2, 3.3.2.2.4, 3.4.2.2.3, 3.2.2.2.8, 3.3.2.2.8, 3.4.2.2.7, 3.2.2.2.10, 3.3.2.2.10, and 3.4.2.2.9.] Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.	6 months prior to the subsequent period of extended operation.
XI.M37	Flux Thimble Tube Inspection	This program inspects for the thinning of flux thimble tube walls, which provides a path for the in-core neutron flux monitoring system detectors and forms part of the reactor coolant system pressure boundary. Flux thimble tubes	Program and SLR enhancements, when applicable, are implemented 6 months prior to

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. A periodic nondestructive examination methodology, such as eddy current testing or other applicant-justified and NRC-accepted inspection methods is used to monitor flux thimble tube wear. This program implements the recommendations of NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors.”	the subsequent period of extended operation.
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	This program is a condition monitoring program that manages loss of material and cracking, as well as hardening or loss of strength of polymeric materials. This program consists of visual inspections of all accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components. Surface examinations or ASME Code Section XI VT-1 examinations are conducted to detect cracking of stainless steel and aluminum components. Aging effects associated with items (except for elastomers) within the scope of AMP XI.M20 (open-cycle cooling water), AMP XI.M21A (closed treated water system), and XI.M27 (fire water system) are not managed by this program. Applicable environments include air, gas, condensation, diesel exhaust, water, fuel oil, and lubricating oil. These internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the subsequent period of extended operation a representative sample of 20% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		service, and severity of operating conditions. Opportunistic inspections continue in each period despite meeting the sampling limit. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this program. If visual inspection of internal surfaces is not possible, a plant-specific program is used. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.	
XI.M39	Lubricating Oil Analysis	This program provides reasonable assurance that the oil environment in the mechanical systems is maintained to the required quality, and the oil systems are maintained free of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. Testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also indicate inleakage and corrosion product buildup.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.M40	Monitoring of Neutron-Absorbing Materials Other than Boraflex	This program relies on periodic inspection, testing, monitoring, and analysis of the criticality design to assure that the required 5% subcriticality margin is maintained. This program consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearance, dimensional measurements, weight, geometric changes (e.g., formation of blisters, pits, and bulges), and boron areal density as observed from coupons or in situ.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
XI.M41	Buried and Underground Piping and Tanks	This program is a condition monitoring program that manages the aging effects associated with the external surfaces of buried and underground piping and tanks such as loss of material and cracking. It addresses piping and tanks composed of any material, including metallic, polymeric, and cementitious materials. The program also manages aging through preventive and mitigative actions (i.e., coatings, backfill quality, and cathodic protection). The number of inspections is based on the effectiveness of the preventive and mitigative actions. Annual cathodic protection surveys are conducted. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured. Inspections are conducted by qualified individuals. When the coatings, backfill, or the condition of exposed piping do not meet the acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the subsequent period of extended operation, an increase in the sample size is conducted. If a reduction of the number of inspections recommended in GALL-SLR Report, AMP XI.M41, Table XI.M41-2 is claimed based on a lack of soil corrosivity as determined by soil testing, then soil testing is conducted once in each 10-year period starting 10 years prior to the subsequent period of extended operation.	The program is implemented and inspections begin within the 10-year period before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
XI.M42	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	This program is a condition monitoring program that manages degradation of internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, lubricating oil, fuel oil, air, or condensation, that can lead to loss of material of base materials or downstream effects such as reduction in flow, reduction in pressure, or reduction of heat transfer when coatings/linings become debris. This program can also be used to manage loss	The program is implemented and inspections begin within the 10-year period before the subsequent period of extended operation. Inspections that are to be completed prior to

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		of coating integrity for external coatings exposed to any air environment or condensation, soil, concrete, or underground environment, that are credited with isolating the external surface of a component from these environments (e.g., as discussed in SRP-SLR Section 3.2.2.2.2). This program manages these aging effects for internal coatings by conducting periodic visual inspections of all coatings/linings applied to the internal surfaces of in-scope components where loss of coating or lining integrity could affect the component’s or downstream component’s intended function(s) identified in the current licensing basis (CLB). Visual inspections are conducted on external surfaces when applicable. For tanks and heat exchangers, all accessible surfaces are inspected. Piping inspections are sampling-based. The training and qualification of individuals involved in coating/lining inspections of noncementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54, including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination are not acceptable. Blisters are evaluated by a coatings specialist with acceptable blisters being small surrounded by sound material and with the size and not increasing in size or frequency between inspections. Minor cracks in cementitious coatings are acceptable if there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining.	the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
XI.M43	High-Density Polyethylene	This program manages the aging effects associated with the internal and external	This program is implemented and

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
	(HDPE) Piping and Carbon Fiber-Reinforced Polymer (CFRP) Repaired Piping	surfaces of HDPE piping and CFRP-repaired piping. The program manages aging through preventive and mitigative actions (i.e., coatings, backfill quality, and cathodic protection), nondestructive examination of pipe wall thicknesses, pressure testing, volumetric inspections, and visual inspections of the pipe from the exterior and/or interior. Opportunistic and periodic examinations are performed to detect loss of material, cracking, and blistering due to wear, environmental exposure (e.g., radiation, temperature, moisture), and flow blockage. For CFRP-repaired piping, the program monitors for delaminations, debonding, tearing, disbonding, and voids in the CFRP layers or laminants, as well as corrosion of the metal substrate at terminal end regions of the CFRP repair. Pressure testing may be used as an alternative to periodic inspections. Any indications of cracking, blistering, wear, CFRP degradation (e.g., tearing, delamination, debonding, disbonding), and flow blockage are evaluated under the corrective actions program. Loss of wall thickness of the metal substrate of CFRP-repaired piping is extrapolated to demonstrate that minimum thickness requirements will continue to be met. Evidence of leakage or drop in pressure during pressure testing is not acceptable.	inspections begin within the 10-year interval before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
XI.S1	ASME Section XI, Subsection IWE Inservice Inspection (IWE)	This program is in accordance with ASME Code Section XI, Subsection IWE, consistent with 10 CFR 50.55a (TN249) “Codes and standards,” with supplemental recommendations. The AMP includes periodic visual, surface, and volumetric examinations, where applicable, of metallic pressure-retaining components of steel containments and concrete containments for signs of degradation, damage, irregularities including discernible liner plate bulges, and for coated areas distress of the underlying metal shell or liner, and corrective actions. The acceptability of inaccessible areas of steel containment shell or concrete containment steel liner is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation and if triggered by plant-specific operating experience, a one-time supplemental volumetric examination by sampling randomly selected as well as focused locations susceptible to loss

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		This program also includes aging management for the potential loss of material due to corrosion in the inaccessible areas of the BWR Mark I steel containment. In addition, the program includes supplemental surface examination to detect cracking for specific pressure-retaining components [identify components] subject to cyclic loading but have no CLB fatigue analysis; and if triggered by plant-specific operating experience, a one-time supplemental volumetric examination by sampling randomly selected as well as focused locations susceptible to loss of thickness due to corrosion of containment shell or liner that is inaccessible from one side. Inspection results are compared with prior recorded results in acceptance of components for continued service.	of thickness due to corrosion of containment shell or liner that is inaccessible from one side is completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
XI.S2	ASME Section XI, Subsection IWL Inservice Inspection (IWL)	This program consists of (1) periodic visual inspection of concrete surfaces for reinforced and pre-stressed concrete containments, and (2) periodic visual inspection and sample tendon testing of unbonded post-tensioning systems for pre-stressed concrete containments for signs of degradation, assessment of damage, and corrective actions, and testing of the tendon corrosion protection medium and free water. Measured tendon lift-off forces are compared to predicted tendon forces calculated in accordance with RG 1.35.1. The Subsection IWL requirements are supplemented to include quantitative acceptance criteria for evaluation of concrete surfaces based on the “Evaluation Criteria” provided in Chapter 5 of ACI 349.3R.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.S3	ASME Section XI, Subsection IWF Inservice inspection (IWF)	This program consists of periodic visual examination of piping and component supports for signs of degradation, evaluation, and corrective actions. This program recommends additional inspections beyond the inspections required by the 10 CFR 50.55a (TN249) ASME Code Section XI, Subsection IWF program. This consists of a one-time inspection of an additional 5% of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. This one-time inspection is conducted within 5 years prior to entering the subsequent period of extended operation. For	The program is implemented and a one-time inspection of an additional 5% of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports is conducted within 5 years prior to the subsequent period of extended

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		high-strength bolting in sizes greater than 1 inch nominal diameter, volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 should be performed to detect cracking in addition to the VT-3 examination. If a component support does not exceed the acceptance standards of IWF-3400 but is electively repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.	operation, and are to be completed prior to the subsequent period of extended operation, are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
XI.S4	10 CFR Part 50, Appendix J	This program consists of monitoring leakage rates through the containment system, its shell or liner, associated welds, penetrations, isolation valves, fittings, and other access openings to detect degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. This program is implemented in accordance with 10 CFR Part 50 Appendix J, RG 1.163 and/or NEI 94-01, and subject to the requirements of 10 CFR Part 54 (TN4878).	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.S5	Masonry Walls	This program consists of inspections, based on IEB 80-11 and plant-specific monitoring proposed by Information Notice (IN) 87-67, for managing shrinkage, separation, gaps, loss of material and cracking of masonry walls such that the evaluation basis is not invalidated and intended functions are maintained.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.S6	Structures Monitoring	This program consists of periodic visual inspection and monitoring of the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as that described in American Concrete Institute (ACI) 349.3R, ACI 201.1R, Structural Engineering Institute/ American Society of Civil Engineers (SEI/ASCE) 11, and other documents) will be detected, the extent of degradation determined	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		and evaluated, and corrective actions taken prior to loss of intended functions. Inspections also include seismic joint fillers, elastomeric materials; and steel edge supports and steel bracings associated with masonry walls, and periodic evaluation of groundwater chemistry and opportunistic inspections for the condition of below-grade concrete. Quantitative results (measurements) and qualitative information from periodic inspections are trended with photographs and surveys for the type, severity, extent, and progression of degradation. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and the quantitative acceptance criteria of ACI 349.3R.	
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	This program consists of inspection and surveillance of raw-water-control structures associated with emergency cooling systems or flood protection. The program also includes structural steel and structural bolting associated with water-control structures. In general, parameters monitored are in accordance with Section C.2 of RG 1.127 and quantitative measurements should be recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. Inspections should occur at least once every 5 years. Structures exposed to aggressive water require additional plant-specific investigation.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
XI.S8	Protective Coating Monitoring and Maintenance	This program ensures that a monitoring and maintenance program implemented in accordance with RG 1.54 is adequate for the subsequent period of extended operation. The program consists of guidance for selection, application, inspection, and maintenance of protective coatings. Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside containment (e.g., steel liner, steel containment shell, structural steel, supports, penetrations, and concrete walls and floors) serve to prevent or minimize loss of material due to corrosion of carbon steel components and aids in decontamination. Degraded coatings in the containment are assessed periodically to	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		ensure post-accident operability of the Emergency Core Cooling System.	
SRP-SLR Appendix A	Plant-Specific AMP	This[fill in name of program] program is a [prevention, mitigation, condition monitoring, performance monitoring] program that manages aging effects associated with [list component type or system as applicable that are in the scope of the program]. Preventive or mitigative actions include [fill in key actions when applicable]. The program manages [list the Aging Effect. Requiring Management] by conducting [periodic, one-time] [describe inspection methods and tests] of [all components or a representative sample of components] within the scope of the program. [When applicable, periodic inspections are conducted every XX years commencing prior to or during the subsequent period of extended operation.] [Describe how inspection and test implementing procedures are controlled (e.g., non-ASME Code inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes that ensure an adequate examination).] Qualitative acceptance criteria are clear enough to reasonably ensure a singular decision is derived based on observed conditions. When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the subsequent period of extended operation, additional inspections are performed.	The program is implemented 6 months prior to the subsequent period of extended operation.

ACI = American Concrete Institute; AMP = aging management program; ASME = American Society of Mechanical Engineers; BWR = boiling water reactor; BWRVIP = Boiling Water Reactor Vessel and Internals Program; CASS = cast austenitic stainless steel; CFR = *Code of Federal Regulations*; CFRP = carbon fiber-reinforced polymer; CRD = control rod drive; EPRI = Electric Power Research Institute; FAC = flow-accelerated corrosion; GALL-SLR = Generic Aging Lessons Learned for Subsequent License Renewal (Report); GL = Generic Letter; HDPE = high-density polyethylene; IASCC = irradiation-assisted stress corrosion cracking; IEB = Inspection and Enforcement Bulletin; ICMH = housing and incore-monitoring housing; ID = inside diameter; IGSCC = intergranular stress corrosion cracking; IN = Information Notice; ISI = inservice inspection; MEB = metal enclosed bus; MRP = Materials Reliability Program; NEI = Nuclear Energy Institute; NPS = nominal pipe size; NRC = U.S. Nuclear Regulatory Commission; OE = operating experience; QA = quality assurance; PWR = pressurized water reactor; PWSCC = primary water stress corrosion cracking; RG = Regulatory Guide; RWCU = reactor water cleanup; SCC = stress corrosion cracking; SEI/ASCE = Structural Engineering Institute/ American Society of Civil Engineers; SRP-SLR = Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plant; TR = Technical Report.

APPENDIX A

QUALITY ASSURANCE FOR AGING MANAGEMENT PROGRAMS

QUALITY ASSURANCE FOR AGING MANAGEMENT PROGRAMS

The subsequent license renewal (SLR) applicant must demonstrate that the effects of aging on structures and components (SCs) subject to an aging management review (AMR) will be managed in a manner that is consistent with the current licensing basis (CLB) of the facility for the subsequent period of extended operation. Therefore, the aspects of the AMR process that affect the quality of safety-related SCs are subject to the quality assurance (QA) requirements of Appendix B of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50 (TN249). For nonsafety-related SCs subject to an AMR, the existing 10 CFR Part 50, Appendix B, QA program may be used to address the elements of corrective actions, confirmation process, and administrative controls. Criterion XVI of 10 CFR Part 50, Appendix B, requires that measures be established to ensure that conditions adverse to quality, such as failures, malfunctions, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, measures must be implemented to ensure that the cause of the condition is determined and that corrective action is taken to preclude repetition. In addition, the cause of the significant condition adverse to quality and the corrective action implemented must be documented and reported to appropriate levels of management.

To preclude repetition of significant conditions adverse to quality, the confirmation process element (Element 8) for SLR aging management programs (AMPs) consists of follow-up actions to verify that the corrective actions implemented are effective in preventing a recurrence. As an example, for the management of internal piping corrosion, the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M2, “Water Chemistry,” may be used to minimize the piping’s susceptibility to corrosion. However, it also may be necessary to institute a condition monitoring program that uses ultrasonic inspection to verify that corrosion is indeed insignificant.

As required by 10 CFR 50.34(b)(6)(i), the final safety analysis report (FSAR) submitted by a nuclear power plant license applicant includes “information on the applicant’s organizational structure, allocations of responsibilities and authorities, and personnel qualification requirements.” 10 CFR 50.34(b)(6)(ii) also notes that Appendix B of 10 CFR Part 50 sets forth the requirements for “managerial and administrative controls used for safe operation.” Pursuant to 10 CFR 50.36(c)(5), administrative controls related to organization and management, procedures, record keeping, review and audit, and reporting ensure the safe operation of the facility. Programs that are consistent with the requirements of 10 CFR Part 50, Appendix B, also satisfy the administrative controls element necessary for AMPs for SLR.

Notwithstanding the suitability of its provisions to address quality-related aspects of the AMR process for SLR, 10 CFR Part 50, Appendix B, covers only safety-related SCs. Therefore, absent a commitment by the applicant to expand the scope of its 10 CFR Part 50, Appendix B, QA program to include nonsafety-related SCs subject to an AMR for SLR, the AMPs applicable to nonsafety-related SCs include alternative means of addressing corrective actions, confirmation processes, and administrative controls. Such alternate means are subject to review by the U.S. Nuclear Regulatory Commission on a case-by-case basis.

An example summary program description of the QA program for the FSAR supplement is shown in Table A-01 below.

Table A-01. FSAR Supplement Summary for Quality Assurance Programs for Aging Management Programs

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule
GALL-SLR Appendix A	Quality Assurance	The quality assurance (QA) program, developed in accordance with the requirements of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50 (TN249), Appendix B, provides the basis for the corrective actions, confirmation process, and administrative controls elements of aging management programs (AMPs). The scope of this existing QA program is expanded to also include nonsafety-related structures and components (SCs) subject to AMPs.	Existing program

AMP = aging management program; CFR = *Code of Federal Regulations*; GALL-SLR = Generic Aging Lessons Learned for Subsequent License Renewal (Report); QA = quality assurance; SCs = structures and components;

APPENDIX B

OPERATING EXPERIENCE FOR AGING MANAGEMENT PROGRAMS

OPERATING EXPERIENCE FOR AGING MANAGEMENT PROGRAMS

Operating experience (OE) is a crucial element of an effective aging management program (AMP). It provides the basis for supporting all other elements of the AMP and, as a continuous feedback mechanism, drives changes to these elements to maintain the overall effectiveness of the AMP. OE should provide objective evidence to support the conclusion that the effects of aging are managed adequately so that the structure- and component-intended function(s) will be maintained during the subsequent period of extended operation. Pursuant to Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” Section 21(a)(3), of Title 10 of the *Code of Federal Regulations* (10 CFR 54.21(a)(3)-TN4878), a license renewal applicant is required to demonstrate that the effects of aging on structures and components subject to an aging management review (AMR) are adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis (CLB) for the period of extended operation.

The systematic review of plant-specific and industry OE concerning aging management and age-related degradation confirms that the subsequent license renewal (SLR) AMPs are, and will continue to be, effective in managing the aging effects for which they are credited. The AMPs should either be enhanced or new AMPs developed, as appropriate, when it is determined through the evaluation of OE that the effects of aging may not be adequately managed. AMPs should be informed by the review of OE on an ongoing basis, regardless of the AMP’s implementation schedule.

B.1 Acceptable Use of Existing Programs

Programs and procedures relied upon to meet the requirements of 10 CFR Part 50, Appendix B, and provisions in NUREG–0737, Item I.C.5, may be used for the capture, processing, and evaluation of OE concerning age-related degradation and aging management during the term of a renewed operating license. As part of meeting the provisions of NUREG–0737, Item I.C.5, the applicant should actively participate in the Institute of Nuclear Power Operations’ (INPOs’) OE program (formerly the Significant Event Evaluation and Information Network [SEE-IN] program endorsed in U.S. Nuclear Regulatory Commission [NRC] Generic Letter 82-04, “Use of INPO SEE-IN Program”). These programs and procedures may also be used for the translation of recommendations from the OE evaluations into plant actions (e.g., enhancement of AMPs and development of new AMPs). While these programs and procedures establish a majority of the functions necessary for the ongoing review of OE, they are also subject to further review as discussed below.

B.2 Areas of Further Review

To ensure that the programmatic activities for the ongoing review of OE are adequate for SLR, the following points should be addressed:

- The programs and procedures relied upon to meet the requirements of 10 CFR Part 50, Appendix B, and provisions in NUREG–0737, Item I.C.5, explicitly apply to and otherwise would not preclude the consideration of OE on age-related degradation and aging management. Such OE can constitute information about the structures and components (SCs) identified in the integrated plant assessment; their materials, environments, aging effects, and aging mechanisms; the AMPs credited for managing the effects of aging; and the activities, criteria, and evaluations integral to the elements of the AMPs. To satisfy this criterion, the applicant should use the option described in the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants, Section A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1),” Position 2, to expand the scope of its 10 CFR Part 50 (TN249), Appendix B, program to include nonsafety-related SCs.

- All final license renewal interim staff guidance documents and revisions to the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report should be considered as sources of industry OE and evaluated accordingly. There should be a process to identify such documents and process them as OE.
- All incoming plant-specific and industry OE should be screened to determine whether it may involve age-related degradation or impacts on aging management activities.
- Relevant research and development information should be reviewed to determine whether it might involve age-related degradation or impacts on aging management activities. Relevant foreign and domestic research and development would generally be subject to a consensus process, and would have used materials and test conditions typical of operating power reactors, including actual operating and environmental conditions. Examples of relevant research and development sources are (1) industry consensus standards development organizations (e.g., American Society of Mechanical Engineers, Institute of Electrical and Electronics Engineers, American Concrete Institute, American Petroleum Institute, National Association of Corrosion Engineers, International Organization for Standardization); (2) Electric Power Research Institute; (3) generic communications issued by the staff based on research conducted by national labs used by the NRC; and (4) nuclear steam supply system vendor and owner’s groups.
- A means should be established within the corrective action program to identify, track, and trend OE that specifically involves age-related degradation. There should also be a process for identifying adverse trends and entering them into the corrective action program for evaluation.
- OE, including relevant research and development items identified as potentially involving aging, should receive further evaluation. The evaluation should specifically take the following into account: (1) systems, structures, and components, (2) materials, (3) environments, (4) aging effects, (5) aging mechanisms, (6) AMPs, and (7) the activities, criteria, and evaluations integral to the elements of the AMPs. The assessment of this information should be recorded with the OE evaluation. If it is found through evaluation that any effects of aging may not be adequately managed, then a corrective action should be entered into the 10 CFR Part 50, Appendix B, program to either enhance the AMPs or develop and implement new AMPs.
- Assessments should be conducted of the effectiveness of the AMPs and activities. The assessments should be conducted on a periodic basis that is not to exceed once every 5 years. They should be conducted regardless of whether the acceptance criteria of the particular AMPs have been met. The assessments should also include evaluation of the AMP or activity relative to the latest NRC and industry guidance documents and standards that are relevant to the particular program or activity. If there is an indication that the effects of aging are not being adequately managed, then a corrective action is entered into the 10 CFR Part 50, Appendix B, program to either enhance the AMPs or develop and implement new AMPs, as appropriate.
- Training on age-related degradation and aging management should be provided to the personnel responsible for implementing the AMPs and those who may submit, screen,

assign, evaluate, or otherwise process plant-specific and industry OE. The scope of training should be linked to the responsibilities for processing OE. This training should occur on a periodic basis and include provisions to accommodate the turnover of plant personnel.

- Guidelines should be established for reporting plant-specific OE on age-related degradation and aging management to the industry. This reporting should be accomplished through participation in the INPOs' OE program.
- Any enhancements necessary to fulfill the above criteria should be put in place no later than the date the subsequently renewed operating license is issued and implemented on an ongoing basis throughout the term of the subsequently renewed license.

The programmatic activities for the ongoing review of plant-specific and industry experience, including relevant research and development concerning age-related degradation and aging management, should be described in the subsequent license renewal application, including the Final Safety Analysis Report (FSAR) supplement. Alternate approaches for the future consideration of OE are subject to NRC review on a case-by-case basis.

An example summary program description of the OE program for the FSAR supplement is shown in Table B-01 below.

Table B-01. FSAR Supplement Summary for Operating Experience Programs for Aging Management Programs

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule
GALL-SLR Appendix B	Operating Experience	This program captures the operating experience (OE) from plant-specific and industry sources and is systematically reviewed on an ongoing basis in accordance with the quality assurance (QA) program, which meets the requirements of 10 CFR Part 50 (TN249), Appendix B, and the OE program, which meets the provisions of NUREG–0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff." This program interfaces with and relies on active participation in the Institute of Nuclear Power Operations' OE program, as endorsed by the U.S. Nuclear Regulatory Commission (NRC). In accordance with these programs, all incoming OE items are screened to determine whether they may involve age-related degradation or aging management impacts. Research and development are also reviewed. Items so identified are further evaluated and the aging management programs (AMPs) are either enhanced or new AMPs are developed, as	The program and necessary enhancements are implemented no later than the date the subsequently renewed operating license is issued.

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		appropriate, when it is determined through these evaluations that the effects of aging may not be adequately managed. Training on age-related degradation and aging management is provided to the personnel responsible for implementing the AMPs and to those who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry OE. Plant-specific OE associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the OE program.	

AMP = aging management program; CFR = *Code of Federal Regulations*; GALL-SLR = Generic Aging Lessons Learned for Subsequent License Renewal (Report); NRC = U.S. Nuclear Regulatory Commission; OE = operating experience; QA = quality assurance.

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When finalized, this report will supersede NUREG-2191, Vol. 2 (Rev. 0)

11. ABSTRACT (200 words or less)

Draft NUREG-2191, Vol. 2, Rev. 1, “Generic Aging Lessons Learned for Subsequent License Renewal Draft Report for Comment,” (GALL-SLR Report) provides guidance to applicants on the content of applications for renewal of the initial renewed operating license, referred to as “subsequent license renewal” (SLR). Draft NUREG–2191 contains the U.S. Nuclear Regulatory Commission (NRC) staff’s generic evaluation of plant aging management programs (AMPs) and establishes the technical basis for their adequacy. The report is revised to incorporate interim staff guidance and lessons learned.

This document is a companion document to Draft NUREG–2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants, Draft Report for Comment” (SRP SLR), Revision 1, that provides guidance to NRC staff on the review of SLR applications. The staff also published Draft NUREG-2221, Supplement 1, “Technical Bases for Changes in the Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG–2192” (Technical Basis Document). Comments on the revised documents will be considered, as appropriate, in the final versions of these documents.

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