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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

Final Report

Office of Nuclear Reactor Regulation

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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). NUREG-2191, Revision 1, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR)" (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 operating experience 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 proposed 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 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 NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants," 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. Such applicants should also note any provisions specifically identified in an AMP where use the of the SLR guidance is not recommended for initial license renewal (e.g., reductions in the scope of the One-Time Inspection Program that apply only to the subsequent period of extended operation – See AMP XI.M32).

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, Revision 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, Revision 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 Revision 1 to the SRP-SLR and Revision 1 to the GALL-SLR. Comments on the revised documents were considered, as appropriate, in the final versions of these documents. A supplement to the Technical Basis Document (NUREG-2221) was also published. Comment disposition by the NRC staff is summarized in Appendix C of this document.

References and supporting documents are listed at the end of each chapter in Volume 2. Supporting documents are not specifically referenced in the GALL-SLR report but are included because they contain relevant background information.

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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
AMPP	Association for Materials Protection and Performance
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)
B&W	Babcock & Wilcox
BWR	boiling water reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CAP	corrective action program
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
CP4	Cathodic Protection Specialist
CRD	control rod drive
CRGT	control rod guide tube
CSE	copper/copper sulfate reference electrode
CUF	cumulative usage factor
CUF_{en}	adjusted cumulative usage factors
CVCS	chemical and volume control system
DOE	U.S. Department of Energy
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
EQ	environmental qualification
FAC	flow-accelerated corrosion
FD	flow distributor
FERC	Federal Energy Regulatory Commission
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
IAEA	International Atomic Energy Agency
IASCC	irradiation-assisted stress corrosion cracking
ICI	incore instruments
ICMH	incore-monitoring housing
ID	inside diameter
IEB	Inspection and Enforcement Bulletin
IGSCC	intergranular stress corrosion cracking
IMI	incore monitoring instrumentation
IN	Information Notice
IS	inside surface
ISG	interim staff guidance
ISP	integrated surveillance program
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
LTCP	low-temperature crack propagation
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
NDTT	nil-ductility transition temperature
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
PEO	period of extended operation
PH	precipitation-hardening (or hardened)
PLL	predicted lower limit
PVC	polyvinyl chloride
PWR	pressurized water reactor
QA	quality assurance
RCIC	reactor core isolation cooling
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RHR	residual heat removal
RPV	reactor pressure vessel
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
SFP	spent fuel pool
SG	steam generator
SIR	silicone rubber
SLC	standby liquid control
SLR	subsequent license renewal
SLRA	subsequent license renewal application
SRM	source range monitor
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
SSPC	Society for Protective Coatings
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
USE	upper-shelf energy
UT	ultrasonic testing
UTS	upper thermal shield
UV	ultraviolet
XLPE	cross-linked polyethylene

INTRODUCTION

The NUREG-2191, Revision 1, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR),” (GALL-SLR Report, Revision. 1, GALL-SLR Report, or simply GALL-SLR) is referenced as a technical basis document in NUREG-2192, Revision 1, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants,” (SRP-SLR, Revision 1, or simply SRP-SLR). The GALL-SLR Report lists generic aging management reviews of systems, structures, and components that may be in the scope of subsequent license renewal applications (SLRAs) and identifies aging management programs that are determined to be acceptable for managing the effects of aging on systems, structures, and components 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 aging management program 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 aging management programs 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 a 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, Revision 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, Revision 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 Revision 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 reactor vessel 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, Revision 0) (ADAMS Accession Nos. ML17187A031, and ML17187A204, for Volumes 1 and 2 respectively)
- Final NUREG-2192, Revision 0, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants." (SRP-SLR, Revision 0) (ADAMS Accession No. ML17188A158)

The GALL-SLR Report, Revision 0, (Accession Nos. ML17187A031, and ML17187A204, for Volumes 1 and 2 respectively), and the companion document SRP-SLR, Revision 0 (SRP-SLR, Revision 0) (Accession No. ML17188A158) were both issued in July 2017. The GALL-SLR Report, Revision 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, Revision 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, Revision 0, and SRP-SLR, Revision 0, several more ISGs, each specifically referred to as 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, Revision 0, and SRP-SLR, Revision 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-2021-02MECHANICAL: “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 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 TLAAs 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.

Table 1 Aging Management Review Column Heading Descriptions (Continued)

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)/Time-Limited Aging Analysis (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.

Table 2 Aging Management Programs Element Descriptions (Continued)

AMP Element	Description
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 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/ TLAAs” 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 American Society of Mechanical Engineers Boiler and Pressure Vessel 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 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

IX.B STRUCTURES AND COMPONENTS

IX.C MATERIALS

IX.D ENVIRONMENTS

IX.E AGING EFFECTS

IX.F SIGNIFICANT 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.

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.
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.

Table IX.B Use of Terms for Structures and Components (Continued)

Term	As Used in this Document
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 (SNL 1994-TN8004). 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.
“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.

Table IX.B Use of Terms for Structures and Components (Continued)

Term	As Used in this Document
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.
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.

Table IX.B Use of Terms for Structures and Components (Continued)

Term	As Used in this Document
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.

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) (ASM 2005-TN8189, ASM 2005-TN8189)

Table IX.C Use of Terms for Materials (Continued)

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. [ASM 2005-TN8189]. Inhibited brass components are resistant to dezincification as a result of the addition of alloying elements such as tin, arsenic, antimony, or phosphorous. [ASM 2002-TN9140, Jones 1996-TN9141].
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, ethylene propylene diene monomer (EPDM), polytetrafluoroethylene elastomers, ethylene tetrafluoroethylene, 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.”
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. [EPRI 2006-TN8195]

Table IX.C Use of Terms for Materials (Continued)

Term	As Used in this Document
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. [ASME 2019-TN8006]
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.
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.

Table IX.C Use of Terms for Materials (Continued)

Term	As Used in this Document
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. [ASME 2008-TN9119, NRC 2011-TN8190, AWS 1982-TN8191].
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. 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. [ASME 2008-TN9119, NRC 2011-TN8190]
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, 25–35% Cr, and 5–20% W. The material is very wear resistant…”

Table IX.C Use of Terms for Materials (Continued)

Term	As Used in this Document
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 [ASM 1986-TN8192]. ASTM Grades 1, 2, 7, 9, 11, or 12 are not susceptible to SCC in seawater or brackish raw water [Boyd and Fink 1978-TN8193].
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.
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.

Table IX.C Use of Terms for Materials (Continued)

Term	As Used in this Document
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 rubber; 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 [Gillen and Clough 1981-TN8194]. 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 [Boyd and Fink 1978-TN8193, Peckner and Bernstein 1977-TN9120, EPRI 2006-TN8195].

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; NRC 1990-TN8197]. 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. [NRC 1996-TN8063]
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 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.
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.

Table IX.D Use of Terms for Environments (Continued)

Term	As Used in this Document
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.

Table IX.D Use of Terms for Environments (Continued)

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 [Freeze and Cherry 1979-TN3275]. 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.

Table IX.D Use of Terms for Environments (Continued)

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.

Table IX.D Use of Terms for Environments (Continued)

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 [Freeze and Cherry 1979-TN3275]. 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.

Table IX.D Use of Terms for Environments (Continued)

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.

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. [NRC 2002-TN8196]
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.

Table IX.E Use of Terms for Aging Effects (Continued)

Term	As Used in this Document
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). [Gillen and Clough 1981-TN8194]
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. [SNL 1996-TN8005, EPRI 2000-TN8054] 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. [NRC 1996-TN9295]
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.

Table IX.E Use of Terms for Aging Effects (Continued)

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.
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.

Table IX.E Use of Terms for Aging Effects (Continued)

Term	As Used in this Document
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). [EPRI 1987-TN9122 and EPRI 1990-TN9123]
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.
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. [JM Eagle 2009-TN8198]

Table IX.E Use of Terms for Aging Effects (Continued)

Term	As Used in this Document
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. [NRC 1996-TN8063]
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. [NRC 1996-TN8063]
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. [NRC 1996-TN9128]
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.
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.

Table IX.F Use of Terms for Aging Mechanisms (Continued)

Term	As Used in this Document
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. [Shah and MacDonald 1993-TN9531, Gavrilas et al. 2000-TN9133]
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. [NUMARC 1991-TN10964]
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.” [ACI 2007-TN9142, ACI 2008-TN9143]
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). [ASTM 1976-TN9134, NUMARC 1992-TN10965] 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. [Shah and MacDonald 1993-TN9531]
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.

Table IX.F Use of Terms for Aging Mechanisms (Continued)

Term	As Used in this Document
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. [Gillen and Clough 1981-TN8194] Degradation may include mechanisms such as cracking, crazing, fatigue breakdown, abrasion, chemical attacks, and change in material properties. [ASM 2000-TN9135, ASTM 2004-TN9136]
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.

Table IX.F Use of Terms for Aging Mechanisms (Continued)

Term	As Used in this Document
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. [NUMARC 1991-TN10964] 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. [NUMARC 1990-TN10966]
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. [EPRI 2013-TN9137]
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.

Table IX.F Use of Terms for Aging Mechanisms (Continued)

Term	As Used in this Document
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. [NUMARC 1991-TN10964, ACI 1988-TN9138]
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.
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. [DNC 2012-TN8199] 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. [EPRI 2001-TN8200] 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.

Table IX.F Use of Terms for Aging Mechanisms (Continued)

Term	As Used in this Document
	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	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 by a corroding (oxidizing) medium.
Intergranular stress corrosion cracking (IGSCC)	IGSCC is SCC in which the cracking occurs along grain boundaries.
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. [NUMARC 1991-TN10964]
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. [NUMARC 1992-TN10965]

Table IX.F Use of Terms for Aging Mechanisms (Continued)

Term	As Used in this Document
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. [SNL 1996-TN8005]
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. [Gavrilas et al. 2000-TN9133]. 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. [ASM 2000-TN9135]
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. [Shah and MacDonald 1993-TN9531]
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. [ASM 2000-TN9135]
Radiolysis	Radiolysis is a chemical reaction induced or assisted by radiation. Radiolysis and photolysis aging mechanisms can occur in ultraviolet-sensitive organic materials.

Table IX.F Use of Terms for Aging Mechanisms (Continued)

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. [Freeze and Cherry 1979-TN3275, ACI 2008-TN9139]
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. [NRC 1996-TN8063]
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. [Gavrilas et al. 2000-TN9133]

Table IX.F Use of Terms for Aging Mechanisms (Continued)

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. [NRC 2002-TN8196]. 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 [NUMARC 1992-TN10965].
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). [EPRI 2000-TN8054, EPRI 1987-TN9122 and EPRI 1990-TN9123]
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.

Table IX.F Use of Terms for Aging Mechanisms (Continued)

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*). [ASTM 1976-TN9134]
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. [NUMARC 1992-TN10965]. 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; 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 ANALYSIS 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 ANALYSIS 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 analysis (TLAA) 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.M1 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) (TN249), 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 (TN249) 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. Qualification under § 50.49 addresses the electrical and mechanical components that are relied upon to ensure the functional capability of the equipment being qualified under the postulated design basis conditions. The mechanical components can include age sensitive items such as gaskets, seals, or O-rings. 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) (TN249) 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 Guidelines; “Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors”; NUREG-0588 (NRC 1981-TN8093), “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment (Category 1 and Category 2 requirements)”; and Regulatory Guide (RG) 1.89 (NRC 2014-TN8087), Revision 1, “Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants,” as applicable. Compliance with 10 CFR 50.49 (TN249) 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) (TN249) 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 (TN249) 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 (TN249) (as further defined and clarified by the Division of Operating Reactors Guidelines,

NUREG-0588 [NRC 1981-TN8093], and RG 1.89 [NRC 2014-TN8087]) 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) (TN249) 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 (NRC 2014-TN8087), Revision 1. Qualification under 10 CFR 50.49 addresses the quantification of electrical and mechanical components under the postulated design basis conditions, that are relied upon to ensure the functional capability of the equipment. The mechanical components can include age-sensitive items such as gaskets, seals, or O-rings. 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 (TN249) 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 (NRC 2009-TN8007) and RG 1.89 (NRC 2014-TN8087), 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 (TN249) 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 (TN249) 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 non-safety-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 (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 non-safety-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 non-safety-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 (TN249) 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 AND SUPPORTING DOCUMENTS

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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 analysis (TLAA) 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) (TN4878). 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 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 (Ware et al. 1995-TN8155); 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 (NRC 2018-TN8151), Revision 1 NUREG/CR-6909 (NRC 2018-TN9702), Revision 1, or other subsequent U.S. Nuclear Regulatory Commission (NRC)-endorsed alternatives. 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 United States of America Standards American National Standards Institute (ANSI) B31.1 (ASME 2014-TN9108) 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) (ASME 2015-TN8213). 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 (ASME 2013-TN8215) 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.

When a flaw is identified by inservice inspection, ASME Code, Section XI, Nonmandatory Appendices A and C (ASME 2015-TN8214) 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 (Ware et al. 1995-TN8155) 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 (NRC 2018-TN8151), Revision 1; NUREG/CR-6909 (NRC 2018-TN9702), 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.

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 non-safety-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 (ASME 2013-TN8215) is an acceptable corrective 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 (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 non-safety-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 non-safety-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 (NRC 2008-TN8205), 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 (NRC 2011-TN8204), 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

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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) (TN4878). 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 (NRC 2014-TN7992), "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 (NRC 2001-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 irradiation embrittlement, IASCC, irradiation-enhanced stress relaxation or creep, 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 (NRC 2001-TN8000). 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 (NRC 2001-TN8000) 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 (EPRI 2009-TN8003), "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 (NRC 2001-TN8000), instead of additional qualification data, is available on

page 3-156 of NUREG-2181 (NRC 2015-TN8001), “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 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 Safety Evaluation Report, 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 (NRC 2001-TN8000)-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 non-safety-related structures and components (SCs) within the scope of this program.

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.

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 (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 non-safety-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 non-safety-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 (NRC 2001-TN8000) 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 (TN249) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 50-TN249

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 Part 50-TN249

10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 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. 2016. 10 CFR Part 50-TN249

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 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 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 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 2008-TN8166), 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 (NRC 1999-TN8126), “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments.” The NRC Regulatory Guide 1.35.1 (NRC 1990-TN8125), “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 (ASME 2008-TN8166), Subsection IWL, when an applicant performs the concrete containment prestressing force TLAA using 10 CFR 54.21(c)(1)(iii) (TN4878).

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 (ASME 2008-TN8166), 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 (ASME 2008-TN8166), 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 non-safety-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 (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 non-safety-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 non-safety-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 (NRC 2012-TN8216), "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 (NRC 1999-TN8126) 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 Analysis in Accordance with 10 CFR 54.21(c)(1)(iii)

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule[(a)]
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) (TN4878). 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.

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 Analysis in Accordance with 10 CFR 54.21(c)(1)(iii) (Continued)

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 analysis (TLAA) 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 (ASME 2014-TN9108) 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 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.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

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 Analysis in Accordance with 10 CFR 54.21(c)(1)(iii) (Continued)

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule[(a)]
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 (NRC 2001-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 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 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	The program is implemented 6 months prior to the subsequent period of extended operation.

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 Analysis in Accordance with 10 CFR 54.21(c)(1)(iii) (Continued)

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule[(a)]
		demonstrate adequate protection of the reactor pressure vessels against the consequences of pressurized thermal shock 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 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 (TN249), 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 pressurized thermal shock 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 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 (TN249), ASME Code Section XI (Subsection IWL; ASME 2008-TN8166) and include construction of trend lines consistent with NRC Information Notice (IN) 99-10 (NRC 1999-TN8126), "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments."	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

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 Analysis in Accordance with 10 CFR 54.21(c)(1)(iii) (Continued)

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule[(a)]
		The NRC RG 1.35.1 (NRC 1990-TN8125), "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.	

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; NRC = U.S. Nuclear Regulatory Commission; PWR = pressurized water reactor; RG = Regulatory Guide; TLAA = time-limited aging analysis.

REFERENCES AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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. ASME 2008-TN8166

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. NRC 1999-TN8126

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_____. 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. NRC 1990-TN8125

CHAPTER XI

AGING MANAGEMENT PROGRAMS

XI AGING MANAGEMENT PROGRAMS

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

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

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

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

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

XI.E4 METAL ENCLOSED BUS

XI.E5 FUSE HOLDERS

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

XI.E7 HIGH VOLTAGE INSULATORS

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

XI.M2 WATER CHEMISTRY

XI.M3 REACTOR HEAD CLOSURE STUD BOLTING

XI.M4 BWR VESSEL ID ATTACHMENT WELDS

XI.M5 DELETED

XI.M6 DELETED

XI.M7 BWR STRESS CORROSION CRACKING

XI.M8 BWR PENETRATIONS

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

XI.M16 PWR VESSEL INTERNALS

XI.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.M37 FLUX THIMBLE TUBE INSPECTION

XI.M38 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

XI.M39 LUBRICATING OIL ANALYSIS

XI.M40 MONITORING OF NEUTRON-ABSORBING MATERIALS OTHER THAN BORAFLEX

XI.M41 BURIED AND UNDERGROUND PIPING AND TANKS

XI.M42 INTERNAL COATINGS/LININGS FOR IN-SCOPE PIPING, PIPING COMPONENTS, HEAT EXCHANGERS, AND TANKS

XI.M43 HIGH DENSITY POLYETHYLENE (HDPE) PIPING AND CARBON FIBER REINFORCED POLYMER (CFRP) REPAIRED PIPING

XI.S1 ASME SECTION XI, SUBSECTION IWE

XI.S2 ASME SECTION XI, SUBSECTION IWL

XI.S3 ASME SECTION XI, SUBSECTION IWF

XI.S4 10 CFR PART 50, APPENDIX J

XI.S5 MASONRY WALLS

XI.S6 STRUCTURES MONITORING

XI.S7 INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

XI.S8 PROTECTIVE COATING MONITORING AND MAINTENANCE

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 and connectors, including those that are coated with fire-retardant material. 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
- 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 (NRC 1992-TN8227), “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 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 provided they can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope cables and connections.

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 (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 non-safety-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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

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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 that can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope cables and connections used in instrumentation circuits, 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 (NRC 1992-TN8227), “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 (TN249), 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 that can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope cables and connections used in instrumentation circuits 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. While insulation resistance testing is a recognized industry standard technique for determining the current condition of cable insulation, insulation resistance should not be used solely for detecting deterioration of electrical insulation systems since it is a pass/fail test that is not particularly sensitive to aging degradation of insulation materials. Therefore, a single insulation test cannot on its own fully assess the aged condition of electrical cable insulation material. 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 (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 non-safety-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 (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 non-safety-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 non-safety-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.

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XI.E3 ELECTRICAL INSULATION FOR INACCESSIBLE ELECTRICAL CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

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). The word “potentially” is necessary to capture environmental unknowns associated with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring (i.e., a cable is assumed to be wet if it cannot be verified that it is dry in inaccessible locations; and therefore, aging management actions are performed on those cables). This ensures that inaccessible cables are conservatively scoped into the AMP and adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function. 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 self-monitoring features and generate failure alarms in a location that is easily identifiable and observable to ensure that the cause of the alarm is appropriately and expeditiously identified and addressed (e.g., a central location, control room, etc.). Alternatively, an alarm that is automatically generated and distributed by way of electronic message (i.e., email, phone call, or text) may be acceptable provided the applicant has demonstrated the method functions as expected (i.e., cell phone coverage is adequate near or onsite and responsible personnel have the capability to receive the messages within a few hours of the alarm being generated), and the electronic message is sent to multiple personnel that have a clear understanding of their expected response and the ability to respond to correct the condition in an expeditious manner. The reliability and methods of ensuring 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 (NRC 1992-TN8227), “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 self-monitoring features and generate failure alarms in a location that is easily identifiable and observable to ensure that the cause of the alarm is appropriately and expeditiously identified and addressed (e.g., a central location, control room, etc.). Alternatively, an alarm that is automatically generated and distributed by way of electronic message (i.e., email, phone call, or text) may be acceptable provided the applicant has demonstrated the method functions as expected (i.e., cell phone coverage is adequate near or onsite and responsible personnel have the capability to receive the messages within a few hours of the alarm being generated), and the electronic message is sent to multiple personnel that have a clear understanding of their expected response and the ability to respond to correct the condition in an expeditious manner. The reliability and methods of ensuring 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 (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 non-safety-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 (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 non-safety-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 non-safety-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.

REFERENCES AND SUPPORTING DOCUMENTS

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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. The word “potentially” is necessary to capture environmental unknowns associated with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring (i.e., a cable is assumed to be wet if it cannot be verified that it is dry in inaccessible locations; and therefore, aging management actions are performed on those cables). This ensures that inaccessible cables are conservatively scoped into the AMP and adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function. 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 self-monitoring features and generate failure alarms in a location that is easily identifiable and observable to ensure that the cause of the alarm is appropriately and expeditiously identified and addressed (e.g., a central location, control room, etc.). Alternatively, an alarm that is automatically generated and distributed by way of electronic message (i.e., email, phone call, or text) may be acceptable provided the applicant has demonstrated the method functions as expected (i.e., cell phone coverage is adequate near or onsite and responsible personnel have the capability to receive the messages within a few hours of the alarm being generated), and the electronic message is sent to multiple personnel that have a clear understanding of their expected response and the ability to respond to correct the condition in an expeditious manner. The reliability and methods of ensuring 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 (that can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope inaccessible instrument and control cables), 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 (NRC 1992-TN8227), “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 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 American wire gauge 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 self-monitoring features and generate failure alarms in a location that is easily identifiable and observable to ensure that the cause of the alarm is appropriately and expeditiously identified and addressed (e.g., a central location, control room, etc.). Alternatively, an alarm that is automatically generated and distributed by way of electronic message (i.e., email, phone call, or text) may be acceptable provided the applicant has demonstrated the method functions as expected (i.e., cell phone coverage is adequate near or onsite and responsible personnel have the capability to receive the messages within a few hours of the alarm being generated), and the electronic message is sent to multiple personnel that have a clear understanding of their expected response and the ability to respond to correct the condition in an expeditious manner. The reliability and methods of ensuring 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 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 (that can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope inaccessible instrument and control cables), 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 (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 non-safety-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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

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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. The word “potentially” is necessary to capture environmental unknowns associated with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring (i.e., a cable is assumed to be wet if it cannot be verified that it is dry in inaccessible locations; and therefore, aging management actions are performed on those cables). This ensures that inaccessible cables are conservatively scoped into the AMP and adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function. 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 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 self-monitoring features and generate failure alarms in a location that is easily identifiable and observable to ensure that the cause of the alarm is appropriately and expeditiously identified and addressed (e.g., a central location, control room, etc.). Alternatively, an alarm that is automatically generated and distributed by way of electronic message (i.e., email, phone call, or text) may be acceptable provided the applicant has demonstrated the method functions as expected (i.e., cell phone coverage is adequate near or onsite and responsible personnel have the capability to receive the messages within a few hours of the alarm being generated), and the electronic message is sent to multiple personnel that have a clear understanding of their expected response and the ability to respond to correct the condition in an expeditious manner. The reliability and methods of ensuring 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 (that can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope inaccessible instrument and control cables) as well as testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power or instrument and control 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 (NRC 1992-TN8227), “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 self-monitoring features and generate failure alarms in a location that is easily identifiable and observable to ensure that the cause of the alarm is appropriately and expeditiously identified and addressed (e.g., a central location, control room, etc.). Alternatively, an alarm that is automatically generated and distributed by way of electronic message (i.e., email, phone call, or text) may be acceptable provided the applicant has demonstrated the method functions as expected (i.e., cell phone coverage is adequate near or onsite and responsible personnel have the capability to receive the messages within a few hours of the alarm being generated), and the electronic message is sent to multiple personnel that have a clear understanding of their expected response and the ability to respond to correct the condition in an expeditious manner. The reliability and methods of ensuring 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 (that can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope inaccessible low-voltage power cables), 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 (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 non-safety-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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

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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 (SNL 1996-TN8005) identified instances of termination loosening at several plants due to thermal cycling and U.S. Nuclear Regulatory Commission Information Notice 2000-14 (NRC 2000-TN8245) 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 (TN249), Appendix B, QA

program to fulfill the corrective actions element of this AMP for both safety-related and non-safety-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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

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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 (NRC 2002-TN8196), “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 (TN249), 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 (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 non-safety-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 (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 non-safety-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 non-safety-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 (NRC 2002-TN8196) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

IEEE. IEEE Standard 1205-2014, “IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Electrical Equipment Used in Nuclear Power Generating Stations and Other Nuclear Facilities.” New York, New York: Institute of Electrical and Electronics Engineers. 2014. IEEE 2014-TN8122

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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 (TN249) 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 (TN249). 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 (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 non-safety-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 (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 non-safety-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 non-safety-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 (NEI 2006-TN8252), "Electrical Cable Connections Not Subject To 10 CFR 50.49 (TN249) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

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IEEE. IEEE Standard 1205-2014, "IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations." New York, New York: Institute of Electrical and Electronics Engineers. 2014. IEEE 2014-TN8122

Licensee Event Report 361/2007-005, "San Onofre Unit 2, Loose Electrical Connection Results in Inoperable Pump Room Cooler." SCE 2008-TN8249

Licensee Event Report 361/2007-006, "San Onofre Units 2 and 3, Loose Electrical Connection Results in One Train of Emergency Chilled Water (ECW) System Inoperable." 2009. SCE 2009-TN8250

Licensee Event Report 361/2008-006, “San Onofre 2, Loose Connection Bolting Results in Inoperable Battery and TS Violation.” 2009. SCE 2008-TN8251

NEI. White Paper, “GALL-SLR AMP XI.E6 (Electrical Cables).” Agencywide Documents Access and Management System (ADAMS) Accession No. ML062770105. Washington, DC: Nuclear Energy Institute. September 5, 2006. NEI 2006-TN8252

NRC. NUREG/CR–5643, “Insights Gained From Aging Research.” ADAMS Accession No. ML041530264. Washington, DC: U.S. Nuclear Regulatory Commission. March 31, 1992. NRC 1992-TN8227

_____. Staff’s Response to the NEI White Paper on Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.” ADAMS Accession No. ML070400349. Washington, DC: U.S. Nuclear Regulatory Commission. March 16, 2007. NRC 2007-TN8253

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 microcracks, 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 other test methods that have been demonstrated to be effective in determining the aged condition of insulators such as 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 (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 non-safety-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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

EPRI. EPRI 1001997, "Parameters that Influence the Aging and Degradation of Overhead Conductors." Palo Alto, California: Electric Power Research Institute. December 2003. EPRI 2003-TN8254

_____. EPRI 1013475, "Plant Support Engineering: License Renewal Electrical Handbook." Revision 1. Palo Alto, California: Electric Power Research Institute. February 2007. EPRI 2007-TN8203

IEEE. IEEE Standard 1205-2014, "IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Electrical Equipment Used in Nuclear Power Generating Stations and Other Nuclear Facilities," New York, New York: Institute of Electrical and Electronics Engineers. 2014. IEEE 2014-TN8122

NRC. NUREG/CR–5643, "Insights Gained From Aging Research." Agencywide Documents Access and Management System (ADAMS) Accession No. ML041530264. Washington, DC: U.S. Nuclear Regulatory Commission. March 31, 1992. NRC 1992-TN8227

_____. Information Notice 93-95: "Storm-Related Loss of Offsite Power Events Due to Salt Buildup on Switchyard Insulators." ADAMS Accession No. ML031070158. Washington, DC: U.S. Nuclear Regulatory Commission. December 13, 1993. NRC 1993-TN7999

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 2008-TN8166), 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 (ASME 2008-TN8166) 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 (TN249) 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 (ASME 2008-TN8166) 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.

[1] GALL-SLR Report, Chapter I, Table I-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 non-safety-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 (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 non-safety-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 non-safety-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:

a. ***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 1980-TN8263), NRC Information Notice (IN) 95-17 (NRC 1995-TN8278), NRC Generic Letter (GL) 94-03 (NRC 1994-TN8262), and NUREG-1544 (NRC 1996-TN8328)]. Cracking due to thermal and mechanical loading has occurred in high-pressure coolant injection piping (NRC IN 89-80) (NRC 1989-TN8274) and instrument lines (Licensee Event Report [LER] 249/99-003-01) (ComEd 2000-TN8257). 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) (NRC 1988-TN8273) and radial cracking (NRC IN 92-57) (NRC 1992-TN8276) 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) (GPU Nuclear 1998-TN8256).

b. ***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 [NRC 1997-TN8279] and 84-18 [NRC 1984-TN8266]), charging pump casing cladding (NRC IN 80-38 [NRC 1980-TN8264] and 94-63 [NRC 1994-TN8277]), instrument nozzles in safety injection tanks (NRC IN 91-05) (NRC 1991-TN8275), control rod drive seal housing (NRC Inspection Report 50-255/99012) (Consumers Energy 1999-TN8335), and safety-related SS piping systems that contain oxygenated, stagnant, or essentially stagnant borated coolant (NRC IN 97-19) (NRC 1997-TN8279). Cracking has occurred in SS baffle former bolts in a number of foreign plants (NRC IN 98-11) (NRC 1998-TN8281) 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 [NRC 1997-TN8051] and NRC Bulletin 88-08 [NRC 1989-TN8261]). Through-wall circumferential cracking has been found in reactor pressure vessel head control rod drive penetration nozzles (NRC IN 2001-05) (NRC 2001-TN8319). Evidence of reactor coolant leakage, together with crack-like indications, has been found in bottom-mounted instrumentation nozzles (NRC IN 2003-11 [NRC 2003-TN8320] and IN 2003-11, Supplement 1 [NRC 2004-TN8322]). Cracking in pressurizer safety and relief line nozzles and in surge line nozzles has been detected (NRC IN 2004-11) (NRC 2004-TN8323), and circumferential cracking in SS pressurizer heater sleeves has also been found (NRC IN 2006-27) (NRC 2006-TN8327). 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) (NRC 2005-TN8326).

c. ***PWR secondary system:*** Steam generator tubes have experienced outside diameter SCC, intergranular attack, wastage, and pitting (NRC IN 97-88) (NRC 1997-TN8280). Carbon steel support plates in steam generators have experienced general corrosion. Steam generator shells have experienced pitting and SCC (NRC Ins 82-37 [NRC 1982-TN8265], 85-65 [NRC 1985-TN8267], and 90-04 [NRC 1990-TN8038]).

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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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.[2] ASME 2008-TN8166

[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.

EPRI. BWRVIP-03, Revision 6 (EPRI 105696-R6), “BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines.” Palo Alto, California: Electric Power Research Institute. December 2003. EPRI 2003-TN8255

Licensee Event Report 219/98-014-00, “Failure of the Isolation Condenser Tube Bundles due to Thermal Stresses/Transgranular Stress Corrosion Cracking Caused by Leaky Valve.” October 1998. GPU Nuclear 1998-TN8256

Licensee Event Report 249/99-003-01, “Supplement to Reactor Recirculation B Loop, High Pressure Flow Element Venturi Instrument Line Steam Leakage Results in Unit 3 Shutdown Due to Fatigue Failure of Socket Welded Pipe Joint.” August 1999. ComEd 2000-TN8257

NRC. Bulletin 88-08, “Thermal Stresses in Piping Connected to Reactor Coolant System.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1988. NRC 1988-TN8082 Supplement 1, June 1988. NRC 1988-TN8259 Supplement 2, September 1988. NRC 1988-TN8260 Supplement 3, April 1989. NRC 1989-TN8261

_____. Generic Letter 94-03, “Intergranular Stress Corrosion Cracking of Core Shrouds in Boiling Water Reactors.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML070600206. Washington, DC: U.S. Nuclear Regulatory Commission. July 1994. NRC 1994-TN8262

NRC. IE Bulletin 80-13, “Cracking in Core Spray Spargers.” Washington, DC: U.S. Nuclear Regulatory Commission. May 1980. NRC 1980-TN8263

_____. Information Notice 80-38, “Cracking in Charging Pump Casing Cladding.” ADAMS Accession No. ML073550834. Washington, DC: U.S. Nuclear Regulatory Commission. October 1980. NRC 1980-TN8264

_____. Information Notice 82-37, “Cracking in the Upper Shell to Transition Cone Girth Weld of a Steam Generator at an Operating PWR.” ADAMS Accession No. ML082970942. Washington, DC: U.S. Nuclear Regulatory Commission. September 1982. NRC 1982-TN8265

_____. Information Notice 84-18, “Stress Corrosion Cracking in PWR Systems.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1984. NRC 1984-TN8266

_____. Information Notice 85-65, “Crack Growth in Steam Generator Girth Welds.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1985. NRC 1985-TN8267

_____. Information Notice 88-03, “Cracks in Shroud Support Access Hole Cover Welds.” Washington, DC: U.S. Nuclear Regulatory Commission. February 1988. NRC 1988-TN8273

_____. Information Notice 89-80, “Potential for Water Hammer, Thermal Stratification, and Steam Binding in High-Pressure Coolant Injection Piping.” Washington, DC: U.S. Nuclear Regulatory Commission. December 1989. NRC 1989-TN8274

_____. Information Notice 90-04, “Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators.” Washington, DC: U.S. Nuclear Regulatory Commission. January 1990. NRC 1990-TN8038

_____. Information Notice 91-05, “Intergranular Stress Corrosion Cracking in Pressurized Water Reactor Safety Injection Accumulator Nozzles.” Washington, DC: U.S. Nuclear Regulatory Commission. January 1991. NRC 1991-TN8275

_____. Information Notice 92-57, “Radial Cracking of Shroud Support Access Hole Cover Welds.” Washington, DC: U.S. Nuclear Regulatory Commission. August 1992. NRC 1992-TN8276

_____. Information Notice 94-63, “Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks.” Washington, DC: U.S. Nuclear Regulatory Commission. August 1994. NRC 1994-TN8277

_____. Information Notice 95-17, “Reactor Vessel Top Guide and Core Plate Cracking.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1995. NRC 1995-TN8278

_____. Information Notice 97-19, “Safety Injection System Weld Flaw at Sequoyah Nuclear Power Plant, Unit 2.” Washington, DC: U.S. Nuclear Regulatory Commission. April 18, 1997. NRC 1997-TN8279

_____. Information Notice 97-46, “Unisolable Crack in High-Pressure Injection Piping.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1997. NRC 1997-TN8051

_____. Information Notice 97-88, “Experiences During Recent Steam Generator Inspections.” Washington, DC: U.S. Nuclear Regulatory Commission. December 1997. NRC 1997-TN8280

_____. Information Notice 98-11, “Cracking of Reactor Vessel Internal Baffle Former Bolts in Foreign Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1998. NRC 1998-TN8281

_____. Information Notice 2001-05, “Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3.” Washington, DC: U.S. Nuclear Regulatory Commission. April 2001. NRC 2001-TN8319

_____. Information Notice 2003-11, “Leakage Found on Bottom-Mounted Instrumentation Nozzles.” Washington, DC: U.S. Nuclear Regulatory Commission. August 2003. NRC 2003-TN8320

_____. Information Notice 2003-11, Supplement 1, “Leakage Found on Bottom-Mounted Instrumentation Nozzles.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2004. NRC 2004-TN8322

_____. Information Notice 2004-11, “Cracking in Pressurizer Safety and Relief Nozzles and in Surge Line Nozzles.” Washington, DC: U.S. Nuclear Regulatory Commission. May 2004. NRC 2004-TN8323

_____. Information Notice 2005-02, “Pressure Boundary Leakage Identified on Steam Generator Drain Bowl Welds.” Washington, DC: U.S. Nuclear Regulatory Commission. February 2005. NRC 2005-TN8326

_____. Information Notice 2006-27, “Circumferential Cracking in the Stainless Steel Pressurizer Heater Sleeves of Pressurized Water Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. December 2006. NRC 2006-TN8327

_____. Inspection Report 50-255/99012, “Palisades Inspection Report.” Item E8.2, Licensee Event Report 255/99-004, “Control Rod Drive Seal Housing Leaks and Crack Indications.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2000. Consumers Energy 1999-TN8335

_____. NUREG–1544, “Status Report: Intergranular Stress Corrosion Cracking of BWR Core Shrouds and Other Internal Components.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1996. NRC 1996-TN8328

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 (EPRI 2014-TN8110) (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 (EPRI 2014-TN8111), "PWR Primary Water Chemistry Guidelines," Revision 7 and EPRI 3002010645 (EPRI 2017-TN8112), "PWR Secondary Water Chemistry Guidelines," Revision 8.

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 non-safety-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 (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 non-safety-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 non-safety-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:

a. ***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 1980-TN8263], NRC Information Notice [IN] 95-17 [NRC 1995-TN8278], NRC Generic Letter [GL] 94-03 [NRC 1994-TN8262], and NUREG-1544 [NRC 1996-TN8328]). 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) (NRC 1992-TN8346).

b. ***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 1996-TN8047], NRC GL 97-01 [NRC 1997-TN8050]). 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 [NRC 1997-TN8279] and 84-18 [NRC 1984-TN8266]), charging pump casing cladding (NRC Ins 80-38 [NRC 1980-TN8264] and 94-63 [NRC 1994-TN8277]), instrument nozzles in safety injection tanks (NRC IN 91-05) (NRC 1991-TN8275), and safety-related SS piping systems that contain oxygenated, stagnant, or essentially stagnant borated coolant (NRC IN 97-19) (NRC 1997-TN8279). Steam generator tubes and plugs and Alloy 600 penetrations have experienced primary water SCC (NRCINs 89-33 [NRC 1989-TN8341], 94-87 [NRC 1994-TN8342], 97-88 [NRC 1997-TN8280], 90-10 [NRC 1990-TN8041], and 96-11 [NRC 1996-TN8047]; NRC Bulletin 89-01 [NRC 1989-TN8347] and its two supplements [NRC 1990-TN9144, NRC 1991-TN9145]). IGSCC-induced circumferential cracking has occurred in PWR pressurizer heater sleeves (NRC IN 2006-27) (NRC 2006-TN8327).

c. **PWR Secondary System:** Steam generator tubes have experienced outside diameter SCC, intergranular attack, wastage, and pitting (NRC IN 97-88 [NRC 1997-TN8280], NRC GL 95-05 [NRC 1995-TN8043]). Carbon steel support plates in steam generators have experienced general corrosion. The steam generator shell has experienced pitting and SCC (NRC INs 82-37 [NRC 1982-TN8265], 85-65 [NRC 1985-TN8267], and 90-04 [NRC 1990-TN8038]). Extensive buildup of deposits at steam generator tube support holes can result in flow-induced vibrations and tube cracking (NRC IN 2007-37) (NRC 2007-TN8345).

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.

REFERENCES AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

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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 (ASME 2008-TN8166); 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 (NRC 2010-TN8358).

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:

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

ii. Using manganese phosphate or other acceptable surface treatments.

iii. 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.

iv. 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). This preventive action is not necessary if cracking is managed by volumetric examination per ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1.

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

[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.

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.

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 non-safety-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 (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 non-safety-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 non-safety-related SCs within the scope of this program.

10 ***Operating Experience:*** SCC has occurred in BWR pressure vessel head studs (Stoller 1991-TN10969). 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 1982-TN8349], NRC Generic Letter 91-17 [NRC 1991-TN8357]).

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 AND SUPPORTING DOCUMENTS

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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 (ASME 2008-TN8166), 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 [EPRI 2004-TN8359]) to provide reasonable assurance of the long-term integrity and safe operation of BWR vessel ID attachment welds.

The guidance in BWRVIP-48-A (EPRI 2004-TN8359) 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 (EPRI 2004-TN8359). 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 (EPRI 2004-TN8359) 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 (EPRI 2004-TN8359) 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 (EPRI 2003-TN8255).

5 ***Monitoring and Trending:*** Inspections scheduled in accordance with ASME Code, Section XI, Subarticle IWB-2400, and BWRVIP-48-A (EPRI 2004-TN8359) 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 (EPRI 2008-TN8301), BWRVIP-59-A (EPRI 2007-TN8312), and Code Case N-896 (ASME 2023-TN10074), respectively.

6 ***Acceptance Criteria:*** The relevant acceptance criteria are provided in BWRVIP-48-A (EPRI 2004-TN8359) 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 non-safety-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 (EPRI 2005-TN8311).

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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

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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.

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 (NRC 1988-TN8039), 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 (NRC 1992-TN8363) 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 (NRC 1988-TN8039), Revision 2 and NRC GL 88-01 (NRC 1992-TN8363), 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 (NRC 1988-TN8039), Revision 2 and GL 88-01 (NRC

1992-TN8363) 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 (NRC 1988-TN8039), Revision 2, and NRC GL 88-01 (NRC 1992-TN8363).

4 ***Detection of Aging Effects:*** The extent, method, and schedule of the inspection and test techniques delineated in NRC GL 88-01 (NRC 1992-TN8363) 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 (EPRI 2005-TN8362). 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 (EPRI 2018-TN8314). 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 (NRC 1992-TN8363) or approved BWRVIP-75-A (EPRI 2005-TN8362) 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 (ASME 2008-TN8166).

Applicable and approved BWRVIP-14-A (EPRI 2008-TN8301), BWRVIP-59-A (EPRI 2007-TN8312), Code Case N-896 (ASME 2023-TN10074), and BWRVIP-62-A (EPRI 2018-TN8314) reports provide guidelines for evaluation of crack growth in SSs, nickel alloys, and low-alloy steels. An applicant may use BWRVIP-61 (EPRI 1999-TN8361) 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 non-safety-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 (NRC 1992-TN8363). 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 (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 non-safety-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 non-safety-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 [NRC 1992-TN8363] and NRC Information Notices 82-39 [NRC 1982-TN8365], 84-41 [NRC 1984-TN8366], and 2004-08). The comprehensive program outlined in NRC GL 88-01, NUREG-0313 (NRC 1988-TN8039), Revision 2, and in the staff-approved BWRVIP-75-A (EPRI 2005-TN8362) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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] ASME 2008-TN8166

[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.

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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. EPRI 2008-TN8301

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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. NRC 1992-TN8363

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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 (EPRI 2002-TN8368), BWRVIP-47-A (EPRI 2004-TN8309), and BWRVIP-27-A (EPRI 2003-TN8367). 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 (EPRI 2005-TN9146) for instrumentation penetrations, in BWRVIP-55-A (EPRI 2005-TN8371) for CRD housing and ICMH penetrations, and in BWRVIP-53-A (EPRI 2005-TN8369) 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 2014-TN8110) 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 (EPRI 2002-TN8368), BWRVIP-47-A (EPRI 2004-TN8309), and BWRVIP-27-A (EPRI 2003-TN8367).

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 (EPRI 2002-TN8368), BWRVIP-47-A (EPRI 2004-TN8309), and BWRVIP-27-A (EPRI 2003-TN8367), 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 (ASME 2008-TN8166), 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 (EPRI 2002-TN8368), BWRVIP-47-A (EPRI 2004-TN8309), or BWRVIP-27-A (EPRI 2003-TN8367) 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 (EPRI 2008-TN8301), BWRVIP-59-A (EPRI 2007-TN8312), and ASME Code Case N-896 (ASME 2023-TN10074) 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 (EPRI 2002-TN8368) for instrumentation nozzles, in BWRVIP-47-A (EPRI 2004-TN8309) for CRD housing and ICMH penetrations, and in BWRVIP-27-A (EPRI 2003-TN8367) 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 non-safety-related structures and components (SCs) within the scope of this program.

Corrective actions include repair and replacement procedures in staff-approved BWRVIP-57-A (EPRI 2005-TN9146), BWRVIP-55-A (EPRI 2005-TN8371), BWRVIP-58-A (EPRI 2005-TN8372), and BWRVIP-53-A (EPRI 2005-TN8369) 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 non-safety-related SCs within the scope of this program.

The staff finds that licensee implementation of the guidelines in BWRVIP-49-A (EPRI 2002-TN8368), BWRVIP-47-A (EPRI 2004-TN8309), and BWRVIP-27-A (EPRI 2003-TN8367), 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 (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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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] ASME 2008-TN8166

[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.

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. EPRI 2008-TN8301

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_____. BWRVIP-58-A (EPRI 1012618), “BWR Vessel and Internals Project, CRD Internal Access Weld Repair.” Palo Alto, California: Electric Power Research Institute. October 2005. EPRI 2005-TN8372

_____. 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. EPRI 2007-TN8312

_____. ASME Code Case N-896, “Reference Crack Growth Rate Curves for Stress Corrosion Cracking of Low Alloy Steels in Boiling Water Reactor Environments,” Section XI, Division 1. New York, New York: American Society of Mechanical Engineers, July 2023. ASME 2023-TN10074

_____. BWRVIP-190 (EPRI 3002002623), “BWR Vessel and Internals Project, BWR Water Chemistry Guidelines,” Revision 1. Palo Alto, California: Electric Power Research Institute. April 2014. EPRI 2014-TN8110

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 ML21147A008 and ML21153A003 [NRC 2021-TN10077]). 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 (EPRI 2005-TN8311) provides guidelines for repair design criteria.
- *Jet pump assembly:* BWRVIP-41, Revision 4-A (EPRI 2018-TN10970) 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., ≥ 5×10^{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 (EPRI 2004-TN8309) provides guidelines for inspection and evaluation; BWRVIP-55-A and BWRVIP-58-A (EPRI 2005-TN8372) provide 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 (ASME 2008-TN8166).

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 (EPRI 1999-TN9147).

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 (EPRI 2008-TN8301), BWRVIP-59-A (EPRI 2007-TN8312), BWRVIP-60-A (EPRI 2003-TN8313), BWRVIP-80-A (EPRI 2007-TN10972), and BWRVIP-99-A (EPRI 2008-TN8318) documents provide additional guidelines for evaluation of crack growth in SSs and nickel alloys. Code Case N-889 (ASME 2018-TN10976) 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 (NRC 2021-TN9215) incorporated by reference in 10 CFR 50.55a (TN249).

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 non-safety-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 (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 non-safety-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 non-safety-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 (NRC 1994-TN8262) 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 (NRC 1996-TN8328); 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) (NRC 1988-TN8273) and radial cracking (NRC IN 92-57) (NRC 1992-TN8276) 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 (NRC 1980-TN8263), and cracking in core spray pipe has been reviewed in BWRVIP-18, Revision 2-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 (NRC 1995-TN8278) discusses cracking in top guides of United States and overseas BWRs. Related experience in other components is reviewed in NRC GL 94-03 (NRC 1994-TN8262) and NUREG-1544 (NRC 1996-TN8328). 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 EPRI 2018-TN9113).

Instances of cracking have occurred in the jet pump assembly (NRC IEB 80-07), hold-down beam (NRC IN 93-101) (NRC 1993-TN9118), and jet pump riser pipe elbows (NRC IN 97-02) (NRC 1997-TN9116). 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) (NRC 2007-TN9114). 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 hold-down 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 (NRC 1988-TN9189) 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 [NRC 2003-TN9199] and NUREG-1823 [NRC 2005-TN9198]).

Borated water leakage from piping and components that are outside the scope of the program established in response to NRC GL 88-05 (NRC 1988-TN9189) 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 (WEC 2012-TN10977).

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 1988-TN9189). 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 (NRC 1988-TN9189) 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 (NRC 1988-TN9189), 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 non-safety-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 (NRC 1988-TN9189) 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) (NRC 2012-TN9197). 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 (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 non-safety-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 non-safety-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 [NRC 1986-TN9191] [and Supplements 1 through 3] [NRC 1987-TN9192, NRC 1987-TN9193, NRC 1995-TN9194] IN 2002-11 [NRC 2002-TN9190], IN 2002-13 [NRC 2002-TN9195], and IN 2003-02 [NRC 2003-TN9196]) and has resulted in significant impairment of component-intended functions in areas that are difficult to access/observe (NRC Bulletin 2002-01) (NRC 2002-TN9188). 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 [FPL 2010-TN9185], LER 346/2002-008 [FENOC 2003-TN9186]). 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) (FENOC 1999-TN9187) or galvanic corrosion caused by wet boric acid crystals bridging between dissimilar metals (EPRI [1000975]) (EPRI 2001-TN8200).

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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

EPRI. EPRI 1000975, “Boric Acid Corrosion Guidebook.” Revision 1. Palo Alto, California: Electric Power Research Institute. November 2001. EPRI 2001-TN8200

Licensee Event Report 250/2010-005, “Containment Liner Through Wall Defect Due to Corrosion.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML103620112. FPL 2010-TN9185

Licensee Event Report 346/2002-008, “Containment Air Coolers Collective Significance of Degraded Conditions.” ADAMS Accession No. ML031330192. May 2003. FENOC 2003-TN9186

Licensee Event Report 346/1998-009, “Reactor Coolant System Pressurizer Spray Valve Degraded with Two of Eight Body-to-Bonnet Nuts Missing.” August 1999. FENOC 1999-TN9187

NRC. Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity.” ADAMS Accession No. ML020770497. Washington, DC: U.S. Nuclear Regulatory Commission. March 2002. NRC 2002-TN9188

_____. Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants.” ADAMS Accession No. ML031130424. Washington, DC: U.S. Nuclear Regulatory Commission. March 1988. NRC 1988-TN9189

_____. Information Notice 86-108, “Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion.” ADAMS Accession Nos. ML031250360, ML031250366, ML053070387, ML053070388. December 1986. NRC 1986-TN9191 Washington, DC: U.S. Nuclear Regulatory Commission. Supplement 1, April 1987 NRC 1987-TN9192; Supplement 2, November 1987 NRC 1987-TN9193; Supplement 3, January 1995 NRC 1995-TN9194.

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_____. Information Notice 2002-13, “Possible Indicators of Ongoing Reactor Pressure Vessel Head Degradation.” ADAMS Accession No. ML020930617. Washington, DC: U.S. Nuclear Regulatory Commission. April 2002. NRC 2002-TN9195

_____. Information Notice 2003-02, “Recent Experience with Reactor Coolant System Leakage and Boric Acid Corrosion.” ADAMS Accession No. ML030160004. Washington, DC: U.S. Nuclear Regulatory Commission. January 2003. NRC 2003-TN9196

_____. Information Notice 2012-15, “Use of Seal Cap Enclosures to Mitigate Leakage from Joints that Use A-286 Bolts.” ADAMS Accession No. ML121740012. Washington, DC: U.S. Nuclear Regulatory Commission. August 2012. NRC 2012-TN9197

_____. NUREG–1823, “U.S. Plant Experience with Alloy 600 Cracking and Boric Acid Corrosion of Light-Water Reactor Pressure Vessel Materials.” Washington, DC: U.S. Nuclear Regulatory Commission. April 2005. NRC 2005-TN9198

_____. Regulatory Issue Summary 2003-13, “NRC Review of Responses to Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity.” ADAMS Accession No. ML032100653. Washington, DC: U.S. Nuclear Regulatory Commission. July 2003. NRC 2003-TN9199

Westinghouse Non-Proprietary Class 3 Report No. WCAP-15988-NP, Revision 2, “Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors.” Pittsburgh, Pennsylvania: Westinghouse Electric Company. June 2012. WEC 2012-TN10977

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 (ASME 2009-TN10979), 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 (TN249), 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 (TN249), 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 (TN249) 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 (ASME 2009-TN10979), 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 (TN249). 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 non-safety-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 (NRC 2021-TN9215).

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 non-safety-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 non-safety-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 (TN249). 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) (NRC 1990-TN8041). The ingress of demineralizer resins also has occurred in operating plants (NRC IN 96-11) (NRC 1996-TN8047). 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 (NRC 1997-TN8050) 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 (NRC 2002-TN9188), and 2002-02 (NRC 2002-TN9207). In addition, PWSCC was observed in reactor vessel bottom-mounted instrument nozzles (NRC IN 2003-11, Supplement 1 [NRC 2004-TN8322], and Licensee Event Report 530/2013-001-00 [APS 2013-TN9202]).

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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 20162021. 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 Case N-722-1, “Additional Examinations for PWR Pressure Retaining Welds in Class 1 Components Fabricated with Alloy 600/82/182 Materials. New York, New York: The American Society of Mechanical Engineers. January 2009. ASME 2007-TN9200

_____. ASME Code Case N-729-1, “Alternative Examination Requirements for PWR Reactor Vessel Upper Heads with Nozzles Having Pressure-Retaining Partial-Penetration Welds.” New York, New York: The American Society of Mechanical Engineers. March 2006. ASME 2006-TN10978

_____. ASME Code Case N-770, “Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities.” New York, New York: The American Society of Mechanical Engineers. January 2009. ASME 2009-TN10979

EPRI. MRP-126, “Generic Guidance for Alloy 600 Management.” Palo Alto, California: Electric Power Research Institute. November 2004. EPRI 2004-TN9201

Licensee Event Report 530/2013-001-00, “Leakage on Reactor Vessel Bottom-Mounted Instrumentation Nozzle 3.” December 2013. APS 2013-TN9202

NEI. NEI 03-08, “Guideline for the Management of Materials Issues.” Revision 2. Washington, DC: Nuclear Energy Institute. January 2010. NEI 2010-TN9203

NRC. Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles.” Washington, DC: U.S. Nuclear Regulatory Commission. August 2001. NRC 2001-TN9206

_____. Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML020770497. Washington, DC: U.S. Nuclear Regulatory Commission. March 2002. NRC 2002-TN9188

_____. Bulletin 2002-02, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs.” Washington, DC: U.S. Nuclear Regulatory Commission. August 2002. NRC 2002-TN9207

_____. Generic Letter 97-01, “Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations.” Washington, DC: U.S. Nuclear Regulatory Commission. April 1997. NRC 1997-TN8050

_____. Information Notice 90-10, “Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600.” Washington, DC: U.S. Nuclear Regulatory Commission. February 1990. NRC 1990-TN8041

_____. Information Notice 96-11, “Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations.” Washington, DC: U.S. Nuclear Regulatory Commission. February 1996. NRC 1996-TN8047

_____. Information Notice 2003-11, “Leakage Found on Bottom-Mounted Instrumentation Nozzles.” Washington, DC: U.S. Nuclear Regulatory Commission. August 2003. NRC 2003-TN8320

_____. Information Notice 2003-11, “Leakage Found on Bottom-Mounted Instrumentation Nozzles.” Supplement 1. Washington, DC: U.S. Nuclear Regulatory Commission. January 2004. NRC 2004-TN8322

_____. Inspection Manual, Inspection Procedure 71111.08, “Inservice Inspection Activities.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2019. NRC 2019-TN9208

_____. NUREG–1823, “U.S. Plant Experience with Alloy 600 Cracking and Boric Acid Corrosion of Light-Water Reactor Pressure Vessel Materials.” Washington, DC: U.S. Nuclear Regulatory Commission. April 2005. NRC 2005-TN9198

_____. Regulatory Guide 1.45, Revision 1, “Guidance on Monitoring and Responding to Reactor Coolant System Leakage.” Washington, DC: U.S. Nuclear Regulatory Commission. May 2008. NRC 2008-TN9209

_____. Regulatory Guide 1.147, Revision 17, “Inservice Inspection Code Case Acceptability.” Washington, DC: U.S. Nuclear Regulatory Commission. August 2014. NRC 2014-TN9210

_____. Regulatory Information Summary 2008-25, “Regulatory Approach for Primary Water Stress Corrosion Cracking of Dissimilar Metal Butt Welds in Pressurized Water Reactor Primary Coolant System Piping.” Washington, DC: U.S. Nuclear Regulatory Commission. October 2008. NRC 2008-TN9211

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 (ASME 1990-TN8131) 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 (NRC 2000-TN9112), 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.

[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) (NRC 2021-TN9178) 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

Mo = molybdenum; 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. 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 (ASME 1990-TN8131) 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 (ASME 2012-TN9212), 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 (TN249). Nonmandatory Appendix C to the 2019 ASME Code, Section XI, provides flaw evaluation procedures for CASS. 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 RG 1.147 (NRC 2021-TN9215). NUREG/CR–4513, Revision 2 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 non-safety-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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

10 CFR 50.55a, "Codes and Standards." Washington, DC: U.S. Nuclear Regulatory Commission. 2022. 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] ASME 2008-TN8166

[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.

_____. ASME Code Section XI, Division 1, Code Case N-824, “Ultrasonic Examination of Cast Austenitic Piping Welds From the Outside Surface.” New York, New York: The American Society of Mechanical Engineers. Approval Date October 16, 2012. ASME 2012-TN9212

_____. ASME Code Section XI, Division 1, Code Case N-481, “Alternative Examination Requirements for Cast Austenitic Pump Casings.” New York, New York: The American Society of Mechanical Engineers. Approval Date March 5, 1990. ASME 1990-TN8131

EPRI. BWRVIP-03, Revision 6 (EPRI 105696-R6), “BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines.” Palo Alto, California: Electric Power Research Institute. December 2003. EPRI 2003-TN8255

_____. MRP-228, “The Materials Reliability Program: Inspection Standard for PWR Internals.” Palo Alto, California: Electric Power Research Institute. 2009. EPRI 2009-TN9213

Grimes, Christopher I., U.S. Nuclear Regulatory Commission, License Renewal and Standardization Branch, letter to Douglas J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-0030, “Thermal Aging Embrittlement of Cast Stainless Steel Components.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML003717179. Washington, DC: U.S. Nuclear Regulatory Commission. May 19, 2000. NRC 2000-TN9112

Lee, S., P.T. Kuo, K. Wichman, and O. Chopra. “Flaw Evaluation of Thermally-Aged Cast Stainless Steel in Light-Water Reactor Applications.” *International Journal of Pressure Vessel and Piping*. pp 37–44. 1997. Lee et al. 1997-TN9174

Maxin, Mark J., letter to Rick Libra (BWRVIP Chairman), Safety Evaluation for Electric Power Research Institute (EPRI) Boiling Water Reactor Vessel and Internals project (BWRVIP) Report TR-105696-R6 (BWRVIP-03), Revision 6, “BWR Vessel and Internals Examination Guidelines (TAC No MC2293).” June 2008. ADAMS Accession No. ML081500814. NRC 2008-TN9214

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. NRC 2021-TN9178

_____. Regulatory Guide 1.147, Revision 20, “Inservice Inspection Code Case Acceptability.” Washington, DC: U.S. Nuclear Regulatory Commission. December 2021. NRC 2021-TN9215

XI.M16 (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 (EPRI 2019-TN8201), "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 (NEI 2017-TN9205), "Guideline for the Management of Materials Issues." The staff found the updated inspection and evaluation guidelines and criteria for PWR RVI components to be acceptable, as documented in the staff's safety evaluation of April 25, 2019 (NRC 2019-TN9222), 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(a)(1)(i), (ii), or (iii) (TN4878). In addition, ASME Code, Section XI includes inspection requirements for PWR removable core support structures in Table IWB-2500-1, Examination Category B-N-3 and for reactor vessel interior

[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.

attachments in Table IWB-2500-1, Examination Category B-N-2, 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 (EPRI 2018-TN9218), 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 non-safety-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 (TN249), 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 (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 non-safety-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 (NEI 2017-TN9205) and the requirements of 10 CFR Part 50 (TN249), 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 non-safety-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 (NEI 2017-TN9205) 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 (NEI 2017-TN9205) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

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

ASME. ASME Code, Section V, "Nondestructive Examination." 2004 Edition[2]. New York, New York: American Society of Mechanical Engineers. ASME 2004-TN9216

_____. ASME Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." New York, New York: American Society of Mechanical Engineers. 2008. ASME 2008-TN8166

EPRI. EPRI Topical Report No. 1016596, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 0)." ADAMS Accession No. ML090160206. Palo Alto, California: Electric Power Research Institute. December 2008. EPRI 2008-TN9217

EPRI. EPRI Topical Report No.1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)." Agencywide Documents Access and Management System (ADAMS) Accession No. ML12017A193 (Transmittal letter from the EPRI-MRP) and ADAMS Accession Nos. ML12017A194, ML12017A196, ML12017A197, ML12017A191, ML12017A192, ML12017A195 and ML12017A199 (Final Report). Palo Alto, California: Electric Power Research Institute. December 2011. EPRI 2011-TN8163

_____. EPRI Proprietary Topical Report No. 3002010399, "Materials Reliability Program: Inspection Standard for PWR Internals (MRP-228, Revision 3)." (Non-publicly available ADAMS Accession No. ML19081A064). The non-proprietary version of the report may be accessed by members of the public at ADAMS Accession No. ML19081A058. Palo Alto, California: Electric Power Research Institute. November 2018. EPRI 2018-TN9218

_____. EPRI Topical Report 3002017168, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A)." ADAMS Accession No. ML20175A112. Palo Alto, California: Electric Power Research Institute. June 2020. EPRI 2019-TN8201

NEI. NEI 03-08, Revision 3, "Guideline for the Management of Materials Issues." ADAMS Accession No. ML19079A253. Washington, DC: Nuclear Energy Institute. February 2017. NEI 2017-TN9205

[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.

NRC. License Renewal Interim Staff Guidance LR-ISG-2011-04, “Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized Water Reactors.” ADAMS Accession No. ML12270A436. Washington, DC: U.S. Nuclear Regulatory Commission. June 3, 2013. NRC 2013-TN9219

_____.. License Renewal Interim Staff Guidance LR-ISG-2011-05, “Ongoing Review Of Operating Experience.” ADAMS Accession No. ML12044A215. Washington, DC: U.S. Nuclear Regulatory Commission. March 16, 2012. NRC 2012-TN9220

_____. Safety Evaluation from Robert A. Nelson (NRC) to Neil Wilmshurst (EPRI), “Revision 1 to the Final Safety Evaluation of Electric Power Research Institute (EPRI) Report, Materials Reliability Program (MRP) Report 1016596 (MRP-227), Revision 0, Pressurized Water Reactor Internals Inspection and Evaluation Guidelines.” ADAMS Accession No. ML11308A770. Washington, DC: U.S. Nuclear Regulatory Commission. December 16, 2011. NRC 2011-TN9221

_____. “Final Safety Evaluation for Electric Power Research Institute Topical Report MRP-227, Revision 1, ‘Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guideline.’” ADAMS Accession No. ML19081A001. Washington, D.C: U.S. Nuclear Regulatory Commission. April 25, 2019. NRC 2019-TN9222

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 (NRC 1989-TN8046), 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 (EPRI 2015-TN9225), “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 (NRC 1989-TN9250) and was further described in NRC GL 89-08 (NRC 1989-TN8046). 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, 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. 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 (EPRI 2015-TN9225), 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) (EPRI 2000-TN9226) 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 (EPRI 2004-TN9223) provides guidance for identifying potential damage locations. EPRI TR-112657 or NUREG/CR-6031 (NRC 1993-TN9251) 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 (EPRI 2015-TN9225), 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 non-safety-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 (EPRI 2007-TN9224).

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. Because a material that is completely resistant to erosion mechanisms is not available, periodic monitoring activities should continue for any component replaced with an alternate material, unless sufficient

follow-up inspections demonstrate that the more resistant material effectively mitigates the loss of material through the end of the period of extended operation. However, if the more resistant material is a coating or lining applied to components' surfaces, then periodic monitoring consistent with XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," is performed.

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 non-safety-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. 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 non-safety-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 1987-TN9238]; NRC Information Notice [IN] 92-35 [NRC 1992-TN9242], IN 95-11 [NRC 1995-TN9244], IN 2006-08 [NRC 2006-TN9247]) and in two-phase piping in extraction steam lines (NRC IN 89-53 [NRC 1989-TN9239], IN 97-84 [NRC 1997-TN9245]) and moisture separator reheater and feedwater heater drains (NRC IN 89-53 [NRC 1989-TN9239], IN 91-18 [NRC 1991-TN9240, NRC 1991-TN9241], IN 93-21 [NRC 1993-TN9243], IN 97-84 [NRC 1997-TN9245]). Observed wall thinning may be due to mechanisms other than FAC or, less commonly, due to a combination of mechanisms (NRC IN 99-19 [NRC 1999-TN9246], Licensee Event Report [LER] 483/1999-003 [Union 2000-TN9236], LER 499/2005-004 [STP 2005-TN9237], LER 277/2006-003 [Exelon 2006-TN9231], LER 237/2007-003 [Exelon 2007-TN9228], LER 254/2009-004 [Exelon 2009-TN9229], LER 374/2013-001 [Exelon 2013-TN9234], LER 374/2015-001 [Exelon 2015-TN9235]). Recent events associated with legacy FAC modeling issues are discussed in NRC IN 2019-08 (NRC 2019-TN9248) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

EPRI. EPRI 1011231, "Recommendations for Controlling Cavitation, Flashing, Liquid Droplet Impingement, and Solid Particle Erosion in Nuclear Power Plant Piping Systems." Palo Alto, California: Electric Power Research Institute. November 2004. EPRI 2004-TN9223

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Licensee Event Report 237/2007-003, “Dresden Unit 2, High Pressure Coolant Injection System Declared Inoperable.” ADAMS Accession No. ML072750663. September 2007. Exelon 2007-TN9228

Licensee Event Report 254/2009-004, “Quad Cities Unit 1, Pinhole Leak in Core Spray Piping Results in Loss of Containment Integrity and Plant Shutdown for Repairs.” ADAMS Accession No. ML093170206. November 2009. Exelon 2009-TN9229

Licensee Event Report 277/2006-003, “Peach Bottom Unit 2, Elbow Leak on Piping Attached to Suppression Pool Results in Loss of Containment Integrity.” ADAMS Accession No. ML063420059. December 2006. Exelon 2006-TN9231

Licensee Event Report 286/2018-003, “Indian Point Unit 3, Manual Reactor Trip Due to a Steam Leak on a High Pressure Feedwater Heater.” ADAMS Accession No. ML18341A122. November 2018. Entergy 2018-TN9232

Licensee Event Report 346/2015-002, “Davis-Besse, Improper Flow Accelerated Corrosion Model Results in 4-Inch Steam Line Failure and Manual Reactor Trip.” ADAMS Accession No. ML15194A013. July 2015 FENOC 2015-TN9233

Licensee Event Report 374/2013-001, “LaSalle Unit 2, Pin Hole Leaks Identified in High Pressure Core Spray Piping.” ADAMS Accession No. ML13168A576. June 2013. Exelon 2013-TN9234

Licensee Event Report 374/2015-001, “LaSalle Unit 2, High Pressure Core Spray Inoperable Due to Division 3 Diesel Generator Cooling Water Pump Casing Leak.” ADAMS Accession No. ML15058A462. February 2015. Exelon 2015-TN9235

Licensee Event Report 483/1999-003, “Callaway, Manual Reactor Trip due to Heater Drain System Pipe Rupture Caused by Flow Accelerated Corrosion.” ADAMS Accession No. ML003712775. May 2000. Union 2000-TN9236

Licensee Event Report 499/2005-004, “South Texas Project Unit 2, Inoperability of Essential Cooling Water 2A and 2B Trains.” ADAMS Accession No. ML053410155. November 2005. STP 2005-TN9237

NRC. Bulletin 87-01, “Thinning of Pipe Walls in Nuclear Power Plants.” ADAMS Accession No. ML031210862. Washington, DC: U.S. Nuclear Regulatory Commission. July 1987. NRC 1987-TN9238

_____. Generic Letter 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning.” ADAMS Accession No. ML031200731. Washington, DC: U.S. Nuclear Regulatory Commission. May 1989. NRC 1989-TN8046

_____. Information Notice 89-53, “Rupture of Extraction Steam Line on High Pressure Turbine.” ADAMS Accession No. ML031180660. Washington, DC: U.S. Nuclear Regulatory Commission. June 1989. NRC 1989-TN9239

_____. Information Notice 91-18, “High-Energy Piping Failures Caused by Wall Thinning.” ADAMS Accession No. ML031190529. Washington, DC: U.S. Nuclear Regulatory Commission. March 1991. NRC 1991-TN9240

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_____. Information Notice 99-19, “Rupture of the Shell Side of a Feedwater Heater at the Point Beach Nuclear Plant.” ADAMS Accession No. ML031040409. Washington, DC: U.S. Nuclear Regulatory Commission. June 1999. NRC 1999-TN9246

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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 (NRC 1990-TN8053), “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants”
- Electric Power Research Institute (EPRI) NP-5769 (EPRI 1988-TN8108), “Degradation and Failure of Bolting in Nuclear Power Plants” (with the exceptions noted in NUREG-1339 for safety related bolting)
- EPRI Report 1015336 (EPRI 2007-TN9254), “Nuclear Maintenance Application Center: Bolted Joint Fundamentals”
- EPRI Report 1015337 (EPRI 2007-TN9255), “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 non-safety-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 (EPRI 2007-TN9254) and 1015337 (EPRI 2007-TN9255) and the additional recommendations of NUREG-1339 (NRC 1990-TN8053) 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 (NRC 1990-TN8053) and in EPRI NP-5769 (EPRI 1988-TN8108).

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 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 non-safety-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 (EPRI 2007-TN9254) and 1015337 (EPRI 2007-TN9255). 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 two additional inspections for each inspection that did not meet the acceptance criteria, or 10 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 (minimum two or 10 percent per unit) 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 (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 non-safety-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 non-safety-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 1982-TN8349), NRC Generic Letter [GL] 91-17) (NRC 1991-TN8357). SCC has occurred in high-strength bolts used for nuclear steam supply system component supports (EPRI NP-5769) (EPRI 1988-TN8108). 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 (EPRI 2007-TN9254), and 1015337 (EPRI 2007-TN9255) and represent industry consensus.

Degradation-related failures have occurred in downcomer tee-quencher bolting in boiling water reactors (BWRs) designed with drywells (NRC 2007-TN9257). Leakage from bolted connections has been observed in the reactor building closed cooling systems of BWRs (Licensee Event Report 341/2005-001) (DTE Energy 2005-TN9256).

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) (NRC 2012-TN9197). 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.

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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 (NRC 2021-TN9320), Volume 1, Revision 5, for Babcock & Wilcox (B&W) PWRs; NUREG-1431 (NRC 2021-TN9321), Volume 1, Revision 5, for Westinghouse PWRs; and NUREG-1432 (NRC 2021-TN9322), 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 (NEI 2011-TN9268), 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 (NEI 2011-TN9268). 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 (NEI 2011-TN9268), 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 (NRC 2017-TN9323), "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) (EPRI 2020-TN9259) provide guidance on monitoring primary-to-secondary leakage. The EPRI Steam Generator Integrity Assessment Guidelines (EPRI 3002020909) (EPRI 2021-TN9262) provide guidance on secondary side activities.

In summary, the NEI 97-06 (NEI 2011-TN9268) 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 (NEI 2011-TN9268) 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) (EPRI 2016-TN9267) 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 (NEI 2011-TN9268) 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 (NEI 2011-TN9268) 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 (NRC 1976-TN8040) and are incorporated into plant TSs. Guidance on assessing the acceptability of flaws is also provided in NEI 97-06 (NEI 2011-TN9268) and the associated EPRI guidelines, including the EPRI Pressurized Water Reactor Steam Generator Examination Guidelines (EPRI 3002007572) (EPRI 2016-TN9267), EPRI Steam Generator *In-Situ* Pressure Test Guidelines

(EPRI 3002007856) (EPRI 2016-TN9260) and EPRI Steam Generator Integrity Assessment Guidelines (EPRI 3002020909) (EPRI 2021-TN9262).

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 (NEI 2011-TN9268) 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 non-safety-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 (NEI 2011-TN9268) 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 (TN249), 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 (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 non-safety-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 (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 non-safety-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 (NEI 2011-TN9268) provides guidance to the industry for routinely sharing pertinent steam generator operating experience (OE) and for incorporating lessons learned from

[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.

plant operation into guidelines referenced in NEI 97-06. The latter includes providing interim guidance to the industry, when needed.

The NEI 97-06 (NEI 2011-TN9268) 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.

REFERENCES AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

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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 (except for certain materials discussed below), 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 (NRC 1989-TN9367), 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 non-safety-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 (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 non-safety-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 non-safety-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 [NRC 1985-TN9371], IN 2007-06, Licensee Event Reports [LER] 247/2001-006 [Entergy 2001-TN9331], LER 306/2004-001 [NMC 2005-TN9357], LER 483/2005-002 [Ameren UE 2005-TN9366], LER 331/2006-003 [FPL Energy 2006-TN9359], LER 255/2007-002 [NMC 2007-TN9334], LER 454/2007-002 [Exelon 2008-TN9363], LER 254/2011-001 [Exelon 2011-TN9333], LER 255/2013-001 [Entergy 2013-TN9335], LER 286/2014-002 [Entergy 2014-TN9354]). Protective coatings have failed, leading to unanticipated corrosion (IN 85-24 [NRC 1985-TN9370], IN 2007-06 [NRC 2007-TN9375], LER 286/2002-001 [Entergy 2002-TN9800], LER 286/2011-003 [Entergy 2011-TN9353]). 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 [NRC 1981-TN9369], IN 86-96 [NRC 1986-TN9372], IN 2004-07 [NRC 2004-TN9373], IN 2006-17 [NRC 2006-TN9374], IN 2007-28 [NRC 2007-TN9376], IN 2008-11 [NRC 2008-TN9377], LER 413/1999-010 [Duke Power 1999-TN9361], LER 305/2000-007 [WPS 2000-TN9355], LER 266/2002-003 [NMC 2003-TN9349], LER 413/2003-004 [Duke Power 2003-TN9362], LER 263/2007-004 [NMC 2007-TN9348], LER 321/2010-002 [Southern Co. 2010-TN9358], LER 457/2011-001 [Exelon 2011-TN9364], LER 457/2011-002 [Exelon 2011-TN9364], LER 397/2013-002 [Energy Northwest 2013-TN9360]). Cracking due to stress corrosion cracking has occurred in brass tubing (LER 305/2002-002) (NMC 2002-TN9356), and pitting in SS has occurred (LER 247/2013-004) (Entergy 2013-TN9332).

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.

REFERENCES AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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

ACI. ACI Standard 201.1R-08, “Guide for Conducting a Visual Inspection of Concrete in Service.” Farmington Hills, Michigan: American Concrete Institute. 2008. ACI 2008-TN9143

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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.[1] ASME 2008-TN8166

EPRI. EPRI 1008282, "Life Cycle Management Sourcebook for Nuclear Plant Service Water Systems." Palo Alto, California: Electric Power Research Institute. March 2005. EPRI 2005-TN9328

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Licensee Event Report 247/2001-006, "Pipe Erosion Results in Service Water System Leakage in Containment." Agencywide Documents Access and Management System (ADAMS) Accession No. ML020090594. December 2001. Entergy 2001-TN9331

Licensee Event Report 247/2013-004, "Technical Specification Prohibited Condition Due to an Inoperable Essential Service Water Header as a Result of Pin Hole Leaks in Code Class 3 SW Piping." ADAMS Accession No. ML13319B082. November 2013. Entergy 2013-TN9332

Licensee Event Report 254/2011-001, "Loss of Both Divisions of Residual Heat Removal System." ADAMS Accession No. ML11174A039. June 2011. Exelon 2011-TN9333

Licensee Event Report 255/2007-002, "Inoperable Containment Due to Containment Air Cooler Through-Wall Flaw." ADAMS Accession No. ML070871046. March 2007. NMC 2007-TN9334

Licensee Event Report 255/2013-001, "Technical Specification Required Shutdown Due to a Component Cooling Water System Leak." ADAMS Accession No. ML13100A019. April 2013. Entergy 2013-TN9335

Licensee Event Report 263/2007-004, "Degradation of Emergency Service Water Flow to Emergency Core Cooling System Room Cooler." ADAMS Accession No. ML072430882. August 2007. NMC 2007-TN9348

Licensee Event Report 266/2002-003, "Possible Common Mode Failure of AFW Due to Partial Clogging of Recirculation Orifices." ADAMS Accession No. ML032890115. October 2003. NMC 2003-TN9349

Licensee Event Report 286/2002-001, "Operation in a Condition Prohibited by Technical Specifications Due to an Inoperable Service Water Pipe Caused by a Leak that Exceeded Allowable Outage Time." ADAMS Accession No. ML022000155. July 2002. Entergy 2002-TN9800

[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.

Licensee Event Report 286/2011-003, “Technical Specification Required Shutdown and a Safety System Functional Failure for a Leaking Service Water Pipe Causing Flooding in the SW Valve Pit Preventing Access for Accident Mitigation.” ADAMS Accession No. ML11123A165. April 2011. Entergy 2011-TN9353

Licensee Event Report 286/2014-002, “Technical Specification Prohibited Condition Due to an Inoperable Essential Service Water Header as a Result of Socket Weld Leak in Code Class 3 SW Piping.” ADAMS Accession No. ML14087A009. March 2014. Entergy 2014-TN9354

Licensee Event Report 305/2000-007, “Alternate Service Water Supply Piping Obstructed.” ADAMS Accession No. ML003726758. June 2000. WPS 2000-TN9355

Licensee Event Report 305/2002-002, “Technical Specifications Required Shutdown: CCW System Leak Could Not Be Repaired Within LCO.” ADAMS Accession No. ML021920465. July 2002. NMC 2002-TN9356

Licensee Event Report 306/2004-001, “Shutdown Required by Technical Specifications Due to Two Trains of Containment Cooling Inoperable.” ADAMS Accession No. ML050890314. March 2005. NMC 2005-TN9357

Licensee Event Report 321/2010-002, “Degraded Plant Service Water Cooling to Main Control Room Air Conditioner Results in Loss of Function.” ADAMS Accession No. ML101650089. June 2010. Southern Co. 2010-TN9358

Licensee Event Report 331/2006-003, “Residual Heat Removal Service Water Pump Inoperable Due to Motor Cooler Failures.” ADAMS Accession No. ML062490486. August 2006. FPL Energy 2006-TN9359

Licensee Event Report 397/2013-002, “Main Control Room Cooler Failed Surveillance.” ADAMS Accession No. ML13141A288. May 2013. Energy Northwest 2013-TN9360

Licensee Event Report 413/1999-010, “Both Catawba Units Operated Outside Their Design Basis and Unit 2 Experienced a Forced Shutdown as a Result of Flow Restriction Caused by Corrosion of the Auxiliary Feedwater System Assured Suction Source Piping Due to Inadequate Testing.” July 1999. Duke Power 1999-TN9361

Licensee Event Report 413/2003-004, “1A Containment Spray System Inoperable for Longer than Technical Specifications Allow Due to Heat Exchanger Fouling.” ADAMS Accession No. ML031970061. July 2003. Duke Power 2003-TN9362

Licensee Event Report 454/2007-002, “Technical Specification Required Shutdown of Unit 1 and Unit 2 Due to an Ultimate Heat Sink Pipe Leak.” ADAMS Accession No. ML080660544. March 2008. Exelon 2008-TN9363

Licensee Event Report 457/2011-001, “Asiatic Clam Shells in Essential Service Water Supply Piping to the 2A Auxiliary Feedwater Pump Resulted in the Auxiliary Feedwater System Inoperability.” ADAMS Accession No. ML112010177. July 2011. Exelon 2011-TN9364

Licensee Event Report 457/2011-002, “Auxiliary Feedwater System Inoperability Due to Additional Asiatic Clam Shells in Essential Service Water Supply Piping.” ADAMS Accession No. ML11263A185. September 2011. Exelon 2011-TN9365

Licensee Event Report 483/2005-002, “Plant Shutdown Required by Technical Specification 3.7.8 for an Inoperable Train of Essential Service Water.” ADAMS Accession No. ML051460343. May 2005. Ameren UE 2005-TN9366

NRC. Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Components.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1989. NRC 1989-TN9367

_____. Generic Letter 89-13, Supplement 1, “Service Water System Problems Affecting Safety-Related Components.” Washington, DC: U.S. Nuclear Regulatory Commission. April 1990. NRC 1990-TN9368

_____. Information Notice 81-21, “Potential Loss of Direct Access to Ultimate Heat Sink.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1981. NRC 1981-TN9369

_____. Information Notice 85-24, “Failures of Protective Coatings in Pipes and Heat Exchangers.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1985. NRC 1985-TN9370

_____. Information Notice 85-30, “Microbiologically Induced Corrosion of Containment Service Water System.” Washington, DC: U.S. Nuclear Regulatory Commission. April 1985. NRC 1985-TN9371

_____. Information Notice 86-96, “Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems.” Washington, DC: U.S. Nuclear Regulatory Commission. November 1986. NRC 1986-TN9372

_____. Information Notice 2004-07, “Plugging of Safety Injection Pump Lubrication Oil Coolers with Lakeweed.” Washington, DC: U.S. Nuclear Regulatory Commission. April 2004. NRC 2004-TN9373

_____. Information Notice 2006-17, “Recent Operating Experience of Service Water Systems Due to External Conditions.” Washington, DC: U.S. Nuclear Regulatory Commission. July 2006. NRC 2006-TN9374

_____. Information Notice 2007-06, “Potential Common Cause Vulnerabilities in Essential Service Water Systems.” Washington, DC: U.S. Nuclear Regulatory Commission. February 2007. NRC 2007-TN9375

_____. Information Notice 2007-28*, “*Potential Common Cause Vulnerabilities in Essential Service Water Systems Due to Inadequate Chemistry Controls.” Washington, DC: U.S. Nuclear Regulatory Commission. September 2007. NRC 2007-TN9376

_____. Information Notice 2008-11, “Service Water System Degradation at Brunswick Steam Electric Plant Unit.” Washington, DC: U.S. Nuclear Regulatory Commission. June 2008. NRC 2008-TN9377

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] [NRC 1989-TN9367]); 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 includes corrosion inhibitors and is designed to maintain the function of

[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.

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, “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. 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. Samples are taken from multiple locations to ensure that a representative sample is examined, focusing on components most susceptible to the applicable aging effect. 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.

  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 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and non-safety-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 two additional inspections for each inspection that did not meet the acceptance criteria, or 10 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 (minimum two or 10 percent per unit) 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 (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 non-safety-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 non-safety-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) (TVA 1993-TN9382) or through-wall cracks in supply lines (LER 280/1991-019) (VEPCO 1991-TN9381) 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) (Xcel 2014-TN9380). 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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.[3] ASME 2008-TN8166

EPRI. EPRI 3002000590, "Closed Cooling Water Chemistry Guideline, Revision 2." Palo Alto, California: Electric Power Research Institute. December 2013. EPRI 2013-TN9378

Flynn, Daniel. The Nalco Water Handbook. Nalco Company. 2009. Flynn 2009-TN9379

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

Licensee Event Report 263/2014-001, “Primary System Leakage Found in Recirculation Pump Upper Seal Heat Exchanger.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML14073A599. March 2014. Xcel 2014-TN9380

Licensee Event Report 280/1991-019, “Loss of Containment Integrity due to Crack in Component Cooling Water Piping.” October 1991. VEPCO 1991-TN9381

Licensee Event Report 327/1993-029, “Inoperable Check Valve in the Component Cooling System as a Result of a Build-Up of Corrosion Products between Valve Components.” December 1993. TVA 1993-TN9382

NRC. Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Components.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1989. NRC 1989-TN9367

_____. Generic Letter 89-13, Supplement 1, “Service Water System Problems Affecting Safety-Related Components.” Washington, DC: U.S. Nuclear Regulatory Commission. April 1990. NRC 1990-TN9368

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 (NRC 1995-TN9390) and NRC Generic Letter (GL) 96-04 (NRC 1996-TN9128), 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 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and non-safety-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 (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 non-safety-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 non-safety-related SCs within the scope of this program.

10 ***Operating Experience:*** NRC IN 87-43 (NRC 1987-TN9388) 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 1993-TN9389), NRC IN 95-38 (NRC 1995-TN9390), and NRC GL 96-04 (NRC 1996-TN9128) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

EPRI. EPRI 1003413, “Guidance and Recommended Procedure for Maintaining and Using RACKLIFE Version 1.10.” Palo Alto, California: Electric Power Research Institute. April 2002. EPRI 2002-TN9383

_____. EPRI NP-6159, “An Assessment of Boraflex Performance in Spent-Nuclear-Fuel Storage Racks.” Palo Alto, California: Electric Power Research Institute. December 1988. EPRI 1988-TN9384

_____. EPRI TR–101986, “Boraflex Test Results and Evaluation, Electric Power Research Institute.” Palo Alto, California: Electric Power Research Institute. March 1993. EPRI 1993-TN9385

_____. EPRI TR–103300, “Guidelines for Boraflex Use in Spent-Fuel Storage Racks.” Palo Alto, California: Electric Power Research Institute. December 1993. EPRI 1993-TN9386

NRC. BNL–NUREG–25582, “Corrosion Considerations in the Use of Boral in Spent Fuel Storage Pool Racks.” Washington, DC: U.S. Nuclear Regulatory Commission. January 1979. NRC 1979-TN9387

_____. Generic Letter 96-04, “Boraflex Degradation in Spent Fuel Pool Storage Racks.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML031110008. Washington, DC: U.S. Nuclear Regulatory Commission. June 26, 1996. NRC 1996-TN9128

_____. 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. NRC 1987-TN9388

_____. Information Notice 93-70, “Degradation of Boraflex Neutron Absorber Coupons.” ADAMS Accession No. ML031070107. Washington, DC: U.S. Nuclear Regulatory Commission. September 10, 1993. NRC 1993-TN9389

_____. Information Notice 95-38, “Degradation of Boraflex Neutron Absorber in Spent Fuel Storage Racks.” ADAMS Accession No. ML031060277. Washington, DC: U.S. Nuclear Regulatory Commission. September 8, 1995. NRC 1995-TN9390

_____. Regulatory Guide 1.26, Revision 3, “Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants (for Comment).” ADAMS Accession No. ML003739964. Washington, DC: U.S. Nuclear Regulatory Commission. February 29, 1979. NRC 1976-TN9391

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 (NRC 1980-TN9395), “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 (ASME 2005-TN9392), “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 (ASME 2005-TN9392), “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 (ASME 2005-TN9392) 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 (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 non-safety-related structures and components (SCs) within the scope of this program.

Repairs are performed as specified in ASME B30.2 (ASME 2005-TN9392) 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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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. ASME 2005-TN9392

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. NRC 1980-TN9393

_____. Generic Letter 81-07, “Control of Heavy Loads.” ADAMS Accession No. ML031080524. Washington, DC: U.S. Nuclear Regulatory Commission. February 3, 1981. NRC 1981-TN9394

_____. NUREG–0612, “Control of Heavy Loads at Nuclear Power Plants.” ADAMS Accession No. ML070250180. Washington, DC: U.S. Nuclear Regulatory Commission. July 31, 1980. NRC 1980-TN9395

_____. 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. NRC 1997-TN8137

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) 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 (NRC 1998-TN9405) 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 (EPRI 1998-TN9403). The American Society of Mechanical Engineers (ASME) operations and maintenance standards and guides (ASME OM-2012, Division 2, Part 28) (ASME 2012-TN9398) 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 (ASME 2012-TN9398), Division 2, Part 28; ANSI/ISA-7.0.01-1996 (ANSI/ISA 1996-TN9397); and EPRI TR–108147 (EPRI 1998-TN9403).

3 ***Parameters Monitored or Inspected:*** Periodic air samples are taken and analyzed for moisture content and corrosive contaminants. 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) (ANSI/ISA 1996-TN9397). 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. Guidance for inspection frequency and inspection methods related to these components is provided in standards or documents such as ASME OM-2012 (ASME 2012-TN9398), 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 (ASME 2012-TN9398), 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 (ANSI/ISA 1996-TN9397). 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 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and non-safety-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 (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 non-safety-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 non-safety-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 (NRC 1981-TN9406), IN 87-28 (NRC 1987-TN9407), IN 87-28, Supplement 1 (NRC 1987-TN9408), and in Licensee Event Report 237/94-005-3 (ComEd 1997-TN9404). 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) (NRC 2008-TN9409). Nevertheless, as a result of NRC GL 88-14 (NRC 1998-TN9405) and in consideration of Institute of Nuclear Power Operations Significant Operating

Experience Report (INPO SOER) 88-01 (INPO 1988-TN10981) and EPRI TR–108147 (EPRI 1998-TN9403), 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

ANSI. ANSI/ISA-7.0.01-1996, “Quality Standard for Instrument Air.” Washington, DC: American National Standards Institute. 1996. ANSI/ISA 1996-TN9397

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. ASME 2012-TN9398

EPRI. EPRI TR–108147, “Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079.” Palo Alto, California: Electric Power Research Institute. March 1998. EPRI 1998-TN9403

INPO. INPO Significant Operating Experience Report 88-01, “Instrument Air System Failures.” Atlanta, Georgia: Institute of Nuclear Power Operations. May 1988. INPO 1988-TN10981

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.” April 3, 1997. ComEd 1997-TN9404

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. NRC 1998-TN9405

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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 (NRC 1988-TN8039), 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 (NRC 1992-TN8363), 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 (NRC 1988-TN8039) 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 1988-TN8039), NRC GL 88-01 (NRC 1988-TN8049), and NRC GL 88-01, Supplement 1 (NRC 1992-TN8363).

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 ((NRC 1988-TN8049) and GL 88-01, Supplement 1 (NRC 1992-TN8363)), 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 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and non-safety-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 (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 non-safety-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 non-safety-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 (NRC 1988-TN8039) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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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[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.

_____. Generic Letter 89-10, “Safety-related Motor Operated Valve Testing and Surveillance.” ADAMS Accession No. ML031150334. Washington, DC: U.S. Nuclear Regulatory Commission. January 24, 1996. NRC 1996-TN10984

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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. Because structural fire barriers and masonry walls have both a structural and fire protection intended function, 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. The applicable procedures for the Structures Monitoring and Fire Protection programs should document their coordination with regards to managing the effects of aging for structural fire barriers, and the applicable procedures for the Masonry Walls and Fire Protection programs should document their coordination with regards to managing the effects of aging for masonry walls that are considered fire barriers. If an applicant does not credit both the Structures Monitoring and Fire Protection programs to manage applicable aging effects for structural fire barriers, or both the Masonry Walls and Fire Protection programs to manage applicable aging effects for masonry walls that are considered fire barriers, then sufficient information should be included in the application and the credited program's applicable procedures to demonstrate that the credited program's inspections, frequency of inspections, and acceptance criteria are capable (equivalent to the Fire Protection, Structures Monitoring, or Masonry Walls programs not credited) of ensuring the intended functions for these components will be maintained.

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 (TN249), "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 (NRC 2021-TN9419), "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) (TN249) 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 (NFPA 2001-TN9421)," 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 (NRC 2021-TN9420), "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 (TN249), 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 systems, structures, 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 periodic 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. Inspection results are documented in sufficient detail so that changes or trends in condition may be identified when compared to previous inspection results. Comparing inspection results only to the immediately prior inspection results (unless inspection results are only available for an immediately prior inspection), may not identify changes or trends in condition occurring over time. 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. The acceptance criteria include (a) 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; (b) no significant indications of cracking and loss of material of fire barrier walls, ceilings, and floors and in other fire barrier materials; (c) no visual indications of missing parts, holes, and wear; (d) no visual indications of cracks or corrosion of fire damper housings; and (e) 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 (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 non-safety-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 (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 non-safety-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 non-safety-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 [NRC 1988-TN9415], IN 94-28 [NRC 1994-TN9417], and IN 97-70 [NRC 1997-TN9418]). Degradation of electrical raceway fire barrier such as small holes, cracking, and unfilled seals are found on routine walkdowns (NRC IN 91-47 [NRC 1991-TN9416] and NRC Generic Letter 92-08 [NRC 1992-TN9413]). 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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

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_____. Information Notice 88-56, “Potential Problems with Silicone Foam Fire Barrier Penetration Seals.” ML031150042. Washington, DC: U.S. Nuclear Regulatory Commission. August 4, 1988. NRC 1988-TN9415

_____. 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. NRC 1991-TN9416

_____. Information Notice 94-28, “Potential Problems with Fire-Barrier Penetration Seals.” ML031060475. Washington, DC: U.S. Nuclear Regulatory Commission. April 5, 1994. NRC 1994-TN9417

_____. Information Notice 97-70, “Potential Problems with Fire Barrier Penetration Seals.” ML031050108. Washington, DC: U.S. Nuclear Regulatory Commission. September 19, 1997. NRC 1997-TN9418

_____. Regulatory Guide 1.189, “Fire Protection for Nuclear Power Plants.” Revision 4. ML21048A441. Washington, DC: U.S. Nuclear Regulatory Commission. May 2021. NRC 2021-TN9419

_____. 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. NRC 2021-TN9420

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.

Sprinklers (i.e., standard, fast response, dry) are either replaced or tested in accordance with Section 5.3.1 of NFPA 25 (NFPA 2011-TN9422), “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) (NFPA 2011-TN9422) 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.

1 ***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 XI.M29-1. 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 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	NFPA 25 Section[q]	Periodicity
Sprinkler Systems		
Sprinkler inspections[b]	5.2.1.1	Annual[d]
Sprinkler testing[e]	5.3.1	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	6.3.1	5-years[f]
Private Fire Service Mains		
Mainline strainer	7.2.2.3	Annual and after each significant flow[g]
Underground and exposed piping flow tests	7.3.1	5-years
Hydrants	7.3.2	Annual [d, h]
Fire Pumps		
Suction screens	8.3.3.7	Annual and after each system actuation[d, i]
Water Storage Tanks		
Exterior inspections	9.2.5.5	Refueling outage interval[j]
Interior inspections	9.2.6, 9.2.7	Three years when tank is not internally coated, otherwise 5 years[k]
Valves and System-Wide Testing		
Main drain test	13.2.5	Annual[d, l, m]
Water Spray Fixed Systems		
Strainers	10.2.1.6, 10.2.1.7, 10.2.7	After each system actuation[d]
Operation test	10.3.4.3	Refueling outage interval[n]
Foam Water Sprinkler Systems		
Strainers	11.2.7.1	After each system actuation
Operational test discharge patterns	11.3.2.6	Annually[d, p]
Storage tanks internal visual inspection for internal corrosion		10 years
Obstruction Investigation		
Internal inspection of piping[o]	14.2	5-years
Obstruction Investigation and Prevention	14.3	When the conditions cited in NFPA 25 (NFPA 2011-TN9422) Sections 14.3.1 (2), (3), (4), (5), (6), (13), or (14) occur

(a) All terms and references are to NFPA 25 (NFPA 2011-TN9422). 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.

Table XI.M27-1. Fire Water System Inspection and Testing Recommendations[a, b, c] (Continued)

(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 (NFPA 2011-TN9422) requirements.

(d) Where NFPA 25 (NFPA 2011-TN9422) 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 (NFPA 2011-TN9422) 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 (NFPA 2011-TN9422) 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 (NFPA 2011-TN9422) 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) Fire pump intake suction screen inspections for flow blockage and loss of material include the fire pump suction strainer when present. The fire pump suction strainer inspections can be conducted every 10 years in lieu of annually and after each system actuation when (1) there is no site-specific operating experience related to flow blockage and loss of material of the fire pump suction strainer; and (2) either the differential pressure across the fire pump suction strainer is monitored or activities are conducted to verify the capability of the upstream fire pump intake suction screens and/or upstream traveling water screens, if present, to prevent pass-through of debris. The application describes the activities to verify the upstream fire pump intake suction screens and/or upstream traveling water screens, if present, capability to prevent pass-through of debris.

(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 (NFPA 2011-TN9422) 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.

Table XI.M27 1 Fire Water System Inspection and Testing Recommendations[a, b, c] (Continued)

(m) For main drain test: Consistent with NFPA 25 (NFPA 2011-TN9422) 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 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 (NFPA 2011-TN9422) Sections 14.2.1.1 and 14.3.2.3 are limited to those that can ensure that flow blockage will not occur.

(p) Where the nature of the protected property is such that foam cannot be discharged, the nozzles or open sprinklers are inspected for correct orientation and the system tested with air to ensure that the nozzles are not obstructed.

(q) "A reference to section includes all sub bullets unless otherwise noted. Section 5.2.1.1 includes Sections 5.2.1.1.1 through 5.2.1.1.7."

2 ***Monitoring and Trending:*** Visual inspection results are monitored and evaluated. System discharge pressure or equivalent methods 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.

3 ***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 or sufficient foreign organic or inorganic materials exist that could cause flow blockage or obstruct pipes, sprinklers, or deluge nozzles.

4 ***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 non-safety-related structures and components (SCs) within the scope of this program.

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 in locations that could be susceptible to the same obstructing material and were not in the scope of the initial tests. 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.

5 ***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 non-safety-related SCs within the scope of this program.

6 ***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 non-safety-related SCs within the scope of this program.

7 ***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) (NRC 2013-TN9423).

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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

NFPA. NFPA 25, "Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems, 2011 Edition." Quincy, Massachusetts: National Fire Protection Association. 2011. NFPA 2011-TN9422

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. NRC 2013-TN9423

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).

Alternatives to Removing Insulation:

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.

   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.

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 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.

Table XI.M29-1 Tank Inspection Recommendations[a, b] (Continued)

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**
Aluminum	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]
	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.

Table XI.M29-1 Tank Inspection Recommendations[a, b] (Continued)

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.

AERM = Aging Effect Requiring Management; AMP = Aging Management Program; GALL-SLR = Generic Aging Lessons Learned for Subsequent License Renewal; IS = inside surface; OS = outside surface; SSC = systems, structures, and components.

(a) The 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 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 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 low-frequency electromagnetic technique 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 (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 non-safety-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 two additional inspections or inspection of 10 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 (minimum two or 10 percent per unit) 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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

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. NRC 2013-TN9424

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. Visual or volumetric inspections are also performed to address stagnant or low flow areas for tanks.

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, or for

tanks with frequent oil inventory turnover, such as Emergency Diesel Fuel Oil Day Tanks, 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 (a).

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 (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 non-safety-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 the fuel oil, or other 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 (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 non-safety-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 non-safety-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 (API 2009-TN9428) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

API. 653, “Tank Inspection, Repair, Alteration, and Reconstruction.” Washington, DC: American Petroleum Institute. April 2009. API 2009-TN9428

ASTM. ASTM D 0975-13, “Standard Specification for Diesel Fuel Oils.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 2004. ASTM 2004-TN9427

_____. 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 1997-TN9429

_____. 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 2000-TN9430

_____. 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. ASTM 1996-TN9431

_____. ASTM D 4057-06 (Reapproved 2011), “Standard Practice for Manual Sampling of Petroleum and Petroleum Products.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 2000. ASTM 2000-TN9432

_____. 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. ASTM 1998-TN9433

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. NRC 2013-TN9425

_____. “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. NRC 2009-TN9426

XI.M31 REACTOR VESSEL MATERIAL SURVEILLANCE

Program Description

Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50 (TN249), 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 (NRC 2014-TN7992), 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 (TN249), 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 (TN249), 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 (NRC 2001-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 (TN249), 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 (TN249), 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 (TN249), 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 (TN249), 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 (NRC 2001-TN8000), 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 (TN249), 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 (ASTM 1982-TN9434) 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 (TN249), 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 (NRC 2001-TN8000), 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, 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 (TN249), 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 (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 non-safety-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 [TN249], 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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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

ASTM. ASTM E 185-82, “Standard Practice for Conducting Surveillance Tests of Light-Water Cooled Nuclear Power Reactor Vessels.” Philadelphia, Pennsylvania: American Society for Testing Materials. (Versions of ASTM E 185 to be used for the various aspects of the reactor vessel surveillance program are as specified in 10 CFR Part 50, Appendix H). 1982. ASTM 1982-TN9434

_____. ASTM E 185-79, “Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels.” Philadelphia, Pennsylvania: American Society for Testing Materials. 1979. ASTM 1979-TN9435

_____. ASTM E 185-73, “Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels.” Philadelphia, Pennsylvania: American Society for Testing Materials. 1973. ASTM 1973-TN9436

Eason, E.D., G.R. Odette, R.K. Nanstad, and T. Yamamoto. “A Physically Based Correlation of Irradiation-Induced Transition Temperature Shifts for RPV Steels.” ORNL/TM-2006/530. ML081000630. Oak Ridge, Tennessee: Oak Ridge National Laboratory. November 2007. ORNL 2007-TN9437

NRC. Regulatory Guide 1.99, “Radiation Embrittlement of Reactor Vessel Materials.” Revision 2. Agencywide Documents Access and Management System (ADAMS) Accession No. ML003740284. Washington, DC: U.S. Nuclear Regulatory Commission. May 31, 1988. NRC 1988-TN8052

_____. Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” ADAMS Accession No. ML010890301. Washington, DC: U.S. Nuclear Regulatory Commission. March 31, 2001. NRC 2001-TN8000

_____. Regulatory Issue Summary 2014-11, “Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components.” ADAMS Accession No. ML14149A165. Washington, DC: U.S. Nuclear Regulatory Commission. October 14, 2014. NRC 2014-TN7992

XI.M32 ONE-TIME INSPECTION

Program Description

A one-time inspection of selected components is conducted 6 months prior to the subsequent period of extended operation or no later than the last refueling outage 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 that unacceptable degradation is not occurring. The scope of the One Time Inspection Program was reduced in GALL-SLR Revision 1; however, those reductions apply only to the subsequent period of extended operation. The full scope of inspections described in the GALL Report (NUREG-1800) to verify the effectiveness of AMPs XI.M2, M30, and M39 remains applicable to the initial period of extended operation.

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. 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 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
- 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)

SCC = systems, structures, and components; UT = ultrasonic testing.
(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 Code inspections follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and

[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.

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 (i.e., made within 10 years of performing the one-time inspection) that may not have

sufficient operating time for aging mechanisms to be bounded by other population samples, the one-time inspection should be performed after sufficient operational exposure has occurred, (i.e., at least 10 years of operational exposure) to provide reasonable confidence in the 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 (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 non-safety-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. However, if the aging effect can be shown to be from an assignable non-systemic cause, alternative options (e.g., an additional one-time inspection performed after replacement of a component found to be non-compatible with the system and environment combination) can be implemented.

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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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.[2] ASME 2008-TN8166

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. EPRI 2003-TN8255

[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.

_____. MRP-228, “Materials Reliability Program: Inspection Standard for PWR Internals.” Palo Alto, California: Electric Power Research Institute. 2009. EPRI 2009-TN9213

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, green copper oxide, or white/grey meringue deposit. 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. A technical justification is submitted with the SLRA when using this sample size for gray cast iron piping exposed to soil (e.g., based on results from inspections previously conducted, lack of adverse operating experience, demonstration of non corrosive soil, condition and robustness of external coatings).
- 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 when technical justification is not submitted.
- 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, green copper oxide; or white/grey meringue deposit; (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 (4) 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 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and non-safety-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 4 years after the end of the 10-year 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 (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 non-safety-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 non-safety-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) (NRC 2016-TN9439).

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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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. EPRI 1998-TN9438

EPRI. EPRI 3002020832, “Electromagnetic NDE Techniques for Detection of Selective Leaching in Gray Cast Iron Piping.” Palo Alto, California: Electric Power Research Institute. September 15, 2021. EPRI 2021-TN10168

EPRI. EPRI 3002020830, “Ultrasonic NDE Techniques for Detection of Selective Leaching in Complex Shaped Gray Cast Iron Components.” Palo Alto, California: Electric Power Research Institute. July 2, 2021. EPRI 2021-TN10169

EPRI. EPRI 3002020822, “Accelerated Testing and Evaluation of Factors Affecting Selective Leaching Susceptibility.” Palo Alto, California: Electric Power Research Institute. September 15, 2021. EPRI 2021-TN10167

EPRI. EPRI 3002016057, “Selective Leaching: State-of-the-Art Technical Update.” Palo Alto, California: Electric Power Research Institute. December 20, 2019. EPRI 2019-TN10170.
Fontana, M.G. *Corrosion Engineering*. McGraw Hill. Pp. 86-90. 1986. Fontana 1986-TN9440

Francis, Roger. (2010). Corrosion of Copper and its Alloys - A Practical Guide for Engineers. NACE International. Francis 2009-TN10166

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. NRC 2016-TN9439

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 mitigate the causes of any past cracking have been implemented. Periodic examinations are

[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.

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 (EPRI 2005-TN9441), "Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146)," and EPRI Technical Report 1018330 (EPRI 2008-TN9442), "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[d] 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[c]	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]

Table XI.M35-1 Examinations (Continued)

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 (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 non-safety-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 (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 non-safety-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 non-safety-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 (NRC 1997-TN8051), "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 (TVA 2009-TN9443) and LER 387/2012-007-00 (Susquehanna 2012-TN9445) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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. ASME 2008-TN8166

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. EPRI 2005-TN9441

_____. Technical Report 1018330, "Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines – Supplemental Guidance (MRP-146S)." Palo Alto, California: Electric Power Research Institute. December 2008. EPRI 2008-TN9442

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.” March 2009. TVA 2009-TN9443 and TVA 2009-TN9444

Licensee Event Report 387/2012-007-00, “Unplanned Shutdown Due to Unidentified Drywell Leakage.” September 2012. PPL Susquehanna 2012-TN9445

NRC. Information Notice 97-46, “Unisolable Crack in High-Pressure Injection Piping.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1997. NRC 1997-TN8051

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 (can also be used for 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.

- 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 [ASME 2014-TN9108]), 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 TR-1007933 (EPRI 2003-TN9447), "Aging

Assessment Field Guide," and TR-1009743 (EPRI 2004-TN9446), "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 non-safety-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 two additional inspections for each inspection that did not meet the acceptance criteria, or 10 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 (minimum two or 10 percent per unit) 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 (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 non-safety-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 non-safety-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 [TN249]) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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 54-TN4878

EPRI. Technical Report 1009743, “Aging Identification and Assessment Checklist.” Palo Alto, California: Electric Power Research Institute. August 2004. EPRI 2004-TN9446

_____. Technical Report 1007933, “Aging Assessment Field Guide.” Palo Alto, California: Electric Power Research Institute. December 2003. EPRI 2003-TN9447

INPO. Good Practice TS-413, “Use of System Engineers.” INPO 85-033. Washington, DC: Institute of Nuclear Power Operations. May 1988. INPO 1988-TN10988

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 (TN249), Appendix B. 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 non-safety-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 (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 non-safety-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 non-safety-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) (NRC 2006-TN9451).

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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

NRC. Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1988. NRC 1988-TN9448

_____. Information Notice No. 87-44, “Thimble Tube Thinning in Westinghouse Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. September 1987. NRC 1987-TN9449

_____. Information Notice No. 87-44, “Thimble Tube Thinning in Westinghouse Reactors.” Supplement 1. Washington, DC: U.S. Nuclear Regulatory Commission. March 1988. NRC 1988-TN9450

_____. 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. NRC 2006-TN9451

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 are conducted under this program. 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. 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 (can also be used for 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.

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 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and non-safety-related structures and components (SCs) within the scope of this program.

Additional inspections are conducted if one of the inspections (i.e., 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 two additional inspections for each inspection that did not meet the acceptance criteria, or 10 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 (minimum two or 10 percent per unit) 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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

EPRI. Technical Report 1007933, “Aging Assessment Field Guide.” Palo Alto, California: Electric Power Research Institute. December 2003. EPRI 2003-TN9447

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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.

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) (ASTM 2002-TN9452). 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 (TN249), Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and non-safety-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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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. ASTM 2002-TN9452

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 (TN249), Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and non-safety-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 (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 non-safety-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 non-safety-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 (NRC 2009-TN9454), "Degradation of Neutron-Absorbing Materials in the Spent Fuel Pool," and is listed below:

1. 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.
2. Blistering has also been noted at many plants. Examples include blistering at Seabrook and Beaver Valley.
3. The significant loss of neutron-absorbing capacity of the plate-type Carborundum material has been reported at Palisades.
4. The coupon testing program at Kewaunee has observed loss of the boron-10 areal density of Tetrabor.

5. The coupon testing programs at Calvert Cliffs Unit 1 and Crystal River Unit 3 have observed weight loss in sheet-type Carborundum.
6. 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

Franke, J.A., Progress Energy, letter to the U.S. Nuclear Regulatory Commission, Crystal River Unit 3–Response to Request for Additional Information for the Review of the Crystal River Unit 3, Nuclear Generating Plant, License Renewal Application. Agencywide Documents Access and Management System (ADAMS) Accession No. ML100290366. January 2010. Progress Energy 2010-TN9453

NRC. Information Notice 2009-26, “Degradation of Neutron-Absorbing Materials in the Spent Fuel Pool.” Washington, DC: U.S. Nuclear Regulatory Commission. October 2009. NRC 2009-TN9454

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Schwarz, C.J., Entergy Nuclear Operations, Inc., Palisades Nuclear Plant, letter to the U.S. Nuclear Regulatory Commission, Commitments to Address Degraded Spent Fuel Pool Storage Rack Neutron Absorber. ADAMS Accession No. ML082410132. Washington, DC: U.S. Nuclear Regulatory Commission. August 2008. Entergy 2008-TN9457

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Spina, J.A., Constellation Energy Nuclear Generation Group, letter to the U.S. Nuclear Regulatory Commission, Calvert Cliffs 1 Response to Request for Additional Information–Long-Term Carborundum Coupon Surveillance Program. ADAMS Accession No. ML080140341. Washington, DC: U.S. Nuclear Regulatory Commission. January 2008. Constellation Energy 2008-TN9459

Warner, M.E., FPL Energy Seabrook Station, letter to the U.S. Nuclear Regulatory Commission, Seabrook Station Boral Spent Fuel Pool Test Coupons Report Pursuant to 10 CFR Part 21.21. ADAMS Accession No. ML032880525. Washington, DC: U.S. Nuclear Regulatory Commission. October 2003. FPL Energy 2003-TN9460

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

Table XI.M41-1 Preventive Actions for Buried and Underground Piping and Tanks (Continued)

Material	Buried	Underground
Aluminum alloy	C, CP, B	None
Cementitious	C, CP, B	C
Polymer	B	None

C = coatings; CP = cathodic protection; B = backfill.

1. 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[1]) SP0169-2007 (NACE 2007-TN9467) or Section 3.4 of NACE RP0285-2002 (NACE 2002-TN9466) as well as the following coating types: asphalt/coal tar enamel, concrete, elastomeric polychloroprene, mastic (asphaltic), epoxy polyethylene, polypropylene, polyurethane, and zinc.
2. 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 (NACE 2007-TN9467) or Section 3.4 of NACE RP0285-2002 (NACE 2002-TN9466).
3. Cathodic protection is in accordance with NACE SP0169-2007 (NACE 2007-TN9467) or NACE RP0285-2002 (NACE 2002-TN9466). 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.
4. Cathodic protection is supplied for reinforced concrete pipe and prestressed concrete cylinder pipe. Applicants provide justification when cathodic protection is not provided.
5. 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).

[1] NACE International and the Society for Protective Coatings (SSPC) merged in 2021 and created the Association for Materials Protection and Performance (AMPP).

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.

6. Backfill is consistent with NACE SP0169-2007 (NACE 2007-TN9467) Section 5.2.3 or NACE RP0285-2002 (NACE 2002-TN9466), Section 3.6. The staff considers backfill that is located within 6 inches of the component that meets ASTM D 448-08 (ASTM 2008-TN9461) 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.

7. 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 (NFPA 2010-TN9470) need not be provided if (1) the system undergoes either a periodic flow test in accordance with NFPA 25 (NFPA 2011-TN9422); (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.

   v. 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 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

Table XI.M41-2 Inspection of Buried and Underground Piping and Tanks (Continued)

Inspections of Buried Piping			
Material	**Preventive Action Categories**		**Inspection See Section 4.c. for Extent of 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 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 (AWWA 2010-TN9462), "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 (EPRI 2015-TN9469), "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.
(b) Tests the soil for soil resistivity, corrosion-accelerating bacteria, pH, moisture, chlorides, sulfates, and redox potential.
(c) 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.
(d) 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 which the 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.

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 non-safety-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 (NFPA 2011-TN9422) 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. The smaller of 10 percent or 60 feet 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 or Association for Materials Protection and Performance (AMPP) 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 (NRC 2010-TN9468), 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 (NFPA 2011-TN9422), 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 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 or AMPP 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 non-safety-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 (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 non-safety-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 non-safety-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 (NACE 2007-TN9467) and NACE RP0285-2002 (NACE 2002-TN9466). 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

ASTM. ASTM D 448-08, "Classification for Sizes of Aggregate for Road and Bridge Construction." West Conshohocken, Pennsylvania: ASTM International. 2008. ASTM 2008-TN9461

AWWA. C105, "Polyethylene Encasement for Ductile-Iron Pipe Systems." Denver, Colorado: American Water Works Association. 2010. AWWA 2010-TN9462

EPRI. EPRI 3002018352, "Recommendations for an Effective Program to Control the Degradation of Buried and Underground Piping and Tanks," (1016456, Revision 2). Palo Alto, California: Electric Power Research Institute. November 2020. EPRI 2020-TN10982

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. ISO 2003-TN9464

NACE. Recommended Practice RP0100-2004, “Standard Recommended Practice, Cathodic Protection of Prestressed Concrete Cylinder Pipelines.” Houston, Texas: NACE International. 2004. NACE 2004-TN9465

_____. Recommended Practice RP0285-2002, “Corrosion Control of Underground Storage Tank Systems by Cathodic Protection.” Houston, Texas: NACE International. April 2002. NACE 2002-TN9466

_____. Standard Practice SP0169-2007, “Control of External Corrosion on Underground or Submerged Metallic Piping Systems.” Houston, Texas: NACE International. 2007. NACE 2007-TN9467

NFPA. NFPA 24, “Standard for the Installation of Private Fire Service Mains and Their Appurtenances.” Quincy, Massachusetts: National Fire Protection Association. 2010. NFPA 2010-TN9470

_____. NFPA 25, “Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems, 2011 Edition.” Quincy, Massachusetts: National Fire Protection Association. 2011. NFPA 2011-TN9422

NRC. 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. NRC 2010-TN9468

_____. EPRI 3002005294, “Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants.” Palo Alto, California: Electric Power Research Institute. November 6, 2015. EPRI 2015-TN9469

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 (EPRI 2009-TN9476), “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 (ACI 2008-TN9143), “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 (NRC 2010-TN9468). 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. For this program element, piping components can be considered as piping of the same 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 (NRC 2010-TN9468), 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
A 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.
B 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:
- 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.
- 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. 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.

  b. 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 (NRC 2010-TN9468), 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 (NRC 2010-TN9468), 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") (ASTM 2009-TN9472).

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 (NRC 2010-TN9468), 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 (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 non-safety-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 (NRC 2010-TN9468) (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 (NRC 2010-TN9468). 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 two additional inspections for each inspection that did not meet the acceptance criteria, or 10 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 (minimum two or 10 percent per unit) 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 non-safety-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 non-safety-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 [NRC 1985-TN9370], "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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 10 CFR Part 50-TN249

10 CFR 54.4(a), “Scope.” Washington, DC: U.S. Nuclear Regulatory Commission. 2016. 10 CFR Part 54-TN4878

ACI. ACI Standard 201.1R-08, “Guide for Conducting a Visual Inspection of Concrete in Service.” Farmington Hills, Michigan: American Concrete Institute. 2008. ACI 2008-TN9143

_____. ACI Standard 349.3R-02, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.” Farmington Hills, Michigan: American Concrete Institute. 2002. ACI 2002-TN9327

ASTM. ASTM 6677-07, “Standard Test Method for Evaluating Adhesion by Knife.” West Conshohocken, Pennsylvania: ASTM International. 2013. ASTM 2013-TN9471

_____. ASTM D714-02, “Standard Test Method for Evaluating Degree of Blistering of Paints.” West Conshohocken, Pennsylvania: ASTM International. 2009. ASTM 2009-TN9472

_____. ASTM D4538-05, “Standard Terminology Relating to Protective Coating and Lining Work for Power Generation Facilities.” West Conshohocken, Pennsylvania: ASTM International. 2006. ASTM 2006-TN9473

_____. ASTM D4541-09, “Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers.” West Conshohocken, Pennsylvania: ASTM International. 2011. ASTM 2011-TN9474

_____. ASTM D7167-12, “Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant.” West Conshohocken, Pennsylvania: ASTM International. 2012. ASTM 2012-TN9475

EPRI. EPRI 1019157, “Guideline on Nuclear Safety-Related Coatings.” Revision 2. (Formerly TR-109937 and 1003102). Palo Alto, California: Electric Power Research Institute. December 2009. EPRI 2009-TN9476

NRC. Information Notice 85-24, “Failures of Protective Coatings in Pipes and Heat Exchangers.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1985. NRC 1985-TN9370

_____. 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. NRC 2010-TN9468

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 buried, underground, safety-related, and in-scope non-safety-related high-density polyethylene (HDPE) piping and carbon fiber-reinforced polymer (CFRP)-repaired piping. The CFRP-repaired piping is defined in this AMP as application of CFRP on the internal surface of metal pipe as structural lining. This program manages aging through preventive, mitigative, inspection, and in some cases, performance monitoring activities. It manages aging effects such as loss of material, cracking, delamination, debonding, and/or blistering. Aging effects can lead to loss of leak tightness, loss of strength, loss of modulus, debris, reduction in flow, and/or flow blockage.

Preventive and mitigative techniques for the HDPE piping and the CFRP-repaired piping between CFRP terminal ends may include the quality of backfill to prevent damage to potentially exposed external surfaces. In addition, preventive and mitigative techniques for the metal substrate of the CFRP-repaired piping at the CFRP terminal ends of the CFRP-repaired piping may include the quality of backfill, and corrosion inhibiting external coatings or cathodic protection. Inspection activities for the HDPE piping and the CFRP-repaired piping may include pressure testing, and volumetric and visual inspections of the exterior and/or interior of the pipe. In addition, inspection activities for the metal substrate of the CFRP-repaired piping at CFRP terminal ends may include electrochemical verification of the effectiveness of cathodic protection, external coatings inspection, and verification of metal substrate wall thickness at the CFRP terminal ends.

These degradations can be affected by improper installation, many years of inservice operation, or a combination or both. Since this would be difficult to determine, AMP XI.M43 was established to monitor the aging effects of HDPE piping and CFRP repaired piping.

The method of GALL-SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks,” may be used for quality of backfill, external coatings, and/or cathodic protection of the metal substrate of the CFRP-required piping at terminal ends, but the wall thickness at the terminal ends are addressed by AMP XI.M43.

The inspections in this AMP are performed once per 10-year inservice inspection interval. The applicant can take credit for inspections performed of CFRP-repaired piping or HDPE piping under other programs such as vendor required inspections, inspections required by NRC-approved alternative request, other NRC Generic Communications, the ASME Code, Section XI, or NRC-approved ASME Code Cases in Regulatory Guide 1.147.

Evaluation and Technical Basis

1 ***Scope of Program:*** This program manages the effects of the aging of the internal and external surfaces of buried, underground, safety-related, and in-scope non-safety-related 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 HDPE is referenced for non-safety-related piping that is in the scope of this AMP, the HDPE should continue to meet the original construction or

fabrication code. When CFRP is referenced, it applies to installation or application of the CFRP repair on the interior surface of a pipe as a structural liner. The program addresses aging effects such as loss of material, cracking, delamination, debonding, and/or blistering. Aging effects can lead to loss of leak tightness, loss of strength, loss of modulus, debris, reduction in flow, and/or flow blockage.

This program is not applicable to exterior surface repair and nonstructural interior surface repair of metal pipe by CFRP.

The methods described in AMP XI.M41 may be used for quality of backfill, external coatings, and/or cathodic protection of the metal substrate of terminal ends, but the metal wall thickness at the terminal ends is addressed by AMP XI.M43.

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 (i.e., the CFRP between terminal ends, and the metal substrate at the CFRP terminal ends) 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 Piping	B	None
CFRP-Repaired Piping (i.e., the CFRP between terminal ends, and the metal substrate at the CFRP terminal ends)	CP[(a)]B[(b)]C[(c)]	C[(c)]

B = backfill; C = coatings; CFRP = Carbon Fiber Reinforced Polymer; CP = cathodic protection; HDPE = High Density Polyethylene.

(a) The metal substrate of the terminal ends of the CFRP-repaired piping may require cathodic protection.

(b) The CFRP between terminal ends of the CFRP-repaired piping may be affected by the backfill when the metal substrate between CFRP terminal ends is degraded completely. The metal substrate of the terminal ends of the CFRP-repaired piping may also be affected by the backfill.

(c) The exterior of the metal substrate of the terminal ends of the CFRP-repaired piping may require coatings.

a. The methods of GALL-SLR Report AMP XI.M41 are used for cathodic protection, external coatings, and/or quality of backfill of the metal substrate of terminal ends of the CFRP-repaired piping, but the wall thickness at the terminal ends is addressed by AMP XI.M43.

b. The CFRP between terminal ends of the CFRP-repaired piping may come in contact with backfill when the metal substrate between terminal ends are degraded completely. Backfill is consistent with Section 5.2.3 of the National Association of Corrosion Engineers (NACE[1]) SP0169-2007 (NACE 2007-TN9467), or Section 3.6 of NACE RP0285-2002 (NACE 2002-TN9466), or original Construction Code. The staff considers backfill that is located within 6 inches of the piping that meets ASTM D 448-08 (ASTM 2008-TN9461) size number 67 (size number 10 for polymeric piping materials) to meet the objectives of NACE SP0169-2007, NACE RP0285-2002, and original Construction Code. Alternatively, backfill quality may be demonstrated by plant records of the original code of construction requirements, or by examining the backfill while conducting the inspections described in the “detection of aging effects” program element of this AMP.

[1] NACE International and the Society for Protective Coatings (SSPC) merged in 2021 and created the Association for Materials Protection and Performance (AMPP).

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, delamination, debonding, blistering, damage, and leakage. Volumetric examination is used to measure wall thickness of the metal substrate at the CFRP terminal ends, detect delamination of CFRP layers, at the terminal ends, and/or detect debonding of the CFRP laminate from metal substrate at CFRP terminal ends.

a. For HDPE piping:

i. Visual inspections of the external and internal surface condition of the HDPE piping are conducted per the requirements of 10 CFR 50.55a (TN249) and/or NRC-approved alternative requests. Visual inspections of the external and internal surface condition of the in-scope non-safety-related HDPE piping are conducted per the requirements of construction code, or plant procedures. In the absence of any of these requirements, the visual inspections are performed per vendor and/or manufacturer requirements. The visual inspections detect:

(1) loss of HDPE material due to wear, temperature, and/or 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, is performed to detect leakage for the piping system that is classified as ASME Code piping. For in-scope non-safety-related piping, a system leakage test is performed to detect leakage in accordance with the original construction code, or in accordance with ASME Code, Section XI if no system leakage test is specified in the original construction code.

iii. For service water system piping, CLB requirements associated with NRC Generic Letter (GL) 89-13 (NRC 1989-TN9367) and associated Supplement 1 (NRC 1990-TN9368) are performed. The visual examination performed under GL 89-13 or under other requirements such as vendor required inspection can be credited for the visual inspection specified in this AMP.

b. For CFRP repaired piping:

i. Visual inspections of the internal surface condition of the CFRP-repaired piping are conducted per the requirements of 10 CFR 50.55a (TN249) and/or NRC-approved alternative requests. In the absence of any of these requirements, the visual inspections are performed per vendor and/or manufacturer requirements. The visual inspections detect the following:

(1) loss of CFRP material due to wear, temperature, and/or moisture;

(2) cracking and/or blistering of CFRP matrix (e.g., due to water absorption);

(3) delaminations, tearing, debonding, and/or voids in CFRP layers;

(4) debonding of CFRP laminate from metal 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; and

(7) accumulation of particulate fouling (raw water systems).

ii. Volumetric examination of the terminal end regions of the CFRP-repaired piping is performed using a nondestructive examination (NDE) technique, e.g., acoustic tap[2], ultrasonic, electrical, magnetic, thermal, microwave, or other applicable nondestructive methods.

(1) Interrogate the CFRP-repaired piping at the terminal ends region to detect delamination of CFRP layers and debonding of CFRP laminate from metal substrate;
(2) Establish a thickness profile of the metal substrate at the CFRP terminal ends to verify conformance with design requirements.

iii. A system leakage test in accordance with the ASME Code, Section XI, paragraph IWA-5000 is performed to detect leakage for the piping system that is classified as ASME Code piping. For in-scope non-safety-related piping, a system leakage test is performed to detect leakage in accordance with the original construction code, or in accordance with ASME Code, Section XI if no system leakage test is specified in the original construction code.

iv. For service water system piping, CLB requirements associated with NRC Generic Letter (GL) 89-13 (NRC 1989-TN9367) and associated Supplement 1 (NRC 1990-TN9368) are performed. The visual examination performed under GL 89-13 or under other requirements such as vendor required inspection can be credited for the visual inspection specified in this AMP.

4 ***Detection of Aging Effects:*** Methods and frequencies used for the detection of aging effects vary based on the material and environment. Opportunistic inspections may be conducted for HDPE piping and CFRP-repaired piping whenever they become accessible.

Periodic inspections of the internal and external surfaces of piping are conducted in accordance with Table XI.M43-2 and XI.M43-3, respectively. 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 Tables XI.M43-2 and XI.M43-3, may be appropriate if exceptions are taken to program element 2, "preventive actions," or in response to plant-specific OE.

[2] 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.

Inspections are conducted during each 10-year inservice inspection interval, 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 examinations if evidence of wall loss beyond minor surface scale or blistering is observed.

Table XI.M43-2 Internal Surface Inspection of Buried and Underground HDPE Piping and CFRP Repaired Piping

Material/Location	Inspection Method	Frequency and Extent of Inspections (See Section 4.b.)
HDPE Piping	Visual	Every inservice inspection interval 20% of the piping length (or a maximum 25 inspections) per material-environment population
CFRP-Repaired Piping (between Terminal Ends and in Terminal End region)	Visual	Every inservice inspection interval Essentially 100% of CFRP-repaired piping length
CFRP-Repaired Piping at the Terminal End Region	Volumetric	Every inservice inspection interval Essentially 100% of terminal end regions

Table XI.M43-3 External Surface Inspection of Buried and Underground HDPE Piping and CFRP Repaired Piping

Buried HDPE Piping and CFRP-Repaired Piping		
Material	**Preventive Action Categories**	**Extent of Inspections (See Section 4.b.)**
HDPE Piping	Backfill is in accordance with the preventive actions program element.	One pipe segment inspection for the external surface of the pipe.
	Backfill is not in accordance with the preventive actions program element.	The smaller of 1% of the length of pipe run or two pipe segment inspections for the external surface of the pipe.
CFRP-Repaired Piping between Terminal Ends	Backfill is in accordance with the preventive actions program element.	One pipe segment inspection for the external surface of the pipe
	Backfill is not in accordance with the preventive actions program element.	The smaller of 1% of the length of pipe run or two pipe segment inspections for the external surface of the pipe.
Metal Substrate of CFRP-Repaired Piping at Terminal Ends	The methods described in GALL-SLR Report AMP XI.M41 may be used for quality of backfill, external coatings, and/or cathodic protection, but the metal wall thickness at the terminal ends is addressed by AMP XI.M43.	The metal substrate at CFRP terminal ends is inspected by ultrasonic examination (or any reliable NDE technique capable of measuring metal wall thickness) from the pipe's internal surface during each inspection interval to ensure the metal substrate wall thickness meets the minimum design requirement.

Underground HDPE Piping and CFRP Repaired Piping	
Material	**Extent of Inspections**
HDPE Piping	1 pipe segment inspection for the external surface of the pipe
CFRP-Repaired Piping between Terminal Ends	1 pipe segment inspection for the external surface of the pipe
Metal Substrate of CFRP-Repaired Piping at Terminal Ends	The methods described in GALL-SLR Report AMP XI.M41 may be used for quality of backfill, external coatings, and/or cathodic protection, but the metal wall thickness at the terminal ends is addressed by AMP XI.M43. The metal substrate at CFRP terminal ends is inspected by ultrasonic examination (or any reliable NDE technique capable of measuring metal wall thickness) from the pipe's internal surface during each inspection interval to ensure the metal substrate wall thickness meets the minimum design requirement.

AMP = aging management program; CFRP = Carbon Fiber Reinforced Polymer; GALL-SLR = Generic Aging Lessons Learned for Subsequent License Renewal; HDPE = High Density Polyethylene; NDE = non-destructive examination.

a. Exceptions to Table XI.M43-3 external surface inspection quantities:

   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. 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. For the CFRP-repaired pipe, the 10 linear feet of pipe should include at least one terminal end.

   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.

b. Guidance related to the extent of inspections for HDPE piping and CFRP-repaired piping is as follows:

   i. When the external 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. For the CFRP-repaired pipe, the 10 linear feet of pipe should include at least one terminal end.

   ii. When the internal HDPE inspections are based on the number of inspections in lieu of the percentage of piping length, any combination of 1-foot-length sections can be used to meet the recommended extent of 25 inspections.

   iii. 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. For the CFRP-repaired pipe, the 10 linear feet of pipe should include at least one terminal end.

c. Piping inspection location selection: Piping inspection locations are selected based on risk (i.e., susceptibility to degradation and consequences of failure). For HDPE piping and CFRP-repaired piping between terminal ends, characteristics such as backfill type and material are considered. Opportunistic examinations of nonleaking pipes may be credited toward examinations if the location selection criteria are met.

d. An alternative to the periodic visual examination of piping external surfaces in Table XI.M43-3: 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.

e. For CFRP-repaired piping, the metal substrate at CFRP terminal ends is inspected by ultrasonic examination (or any reliable NDE technique capable of measuring metal wall thickness) from the pipe's internal surface during each inspection interval to ensure the metal substrate wall thickness meets the minimum design requirement.

5 ***Monitoring and Trending:*** If leak rate testing is conducted for the HDPE piping and CFRP-repaired piping, the results of leak rates are trended when follow-up testing is

performed. Where wall thickness measurements are conducted for the metal substrate at terminal ends of the CFRP-repaired piping, the results of wall thickness measurement 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 to the next 10-year inservice inspection interval 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 not permitted 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 external 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. Cracking is not permitted in the CFRP laminate. Blisters, gouges, or wear of the CFRP laminate are evaluated in accordance with the "corrective actions" program element specified in Section 7 below.

ii. The measured wall thickness of the metal substrate at terminal ends of the CFRP-repaired piping that is extrapolated to degrade with a loss of material to the end of the next 10-year inservice inspection interval shall meet the minimum design wall thickness requirements.

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. Delamination, tearing, debonding, or voids in the CFRP laminate at the terminal end region are unacceptable.

v. Debonding of the CFRP laminate from the metal substrate at each CFRP repair's terminal end region is unacceptable.

vi. Delaminations, tearing, or voids in the CFRP laminate other than terminal end regions are unacceptable.

vii. Backfill is acceptable if the inspections do not reveal evidence that the backfill caused damage to the external surface of the CFRP laminate.

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 non-safety-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 could have resulted in a loss of pressure boundary function when the degradation (e.g., loss of material, cracking, delamination, debonding, and/or blistering) is extrapolated to the end of the next 10-year inservice inspection interval, 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. Sources of leakage detected during pressure tests are identified and corrected.

c. Indications of degradation (e.g., loss of material, cracking, delamination, debonding, and/or blistering) 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 (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 non-safety-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 non-safety-related SCs within the scope of this program.

10 ***Operating Experience:*** OE shows that pipes with CFRP repairs could be degraded. The degradation may be caused by improper installation, many years of inservice operation, or a

combination of both. Since this would be difficult to determine, AMP XI.M43 was established to monitor the aging effects of HDPE piping and CFRP-repaired piping. 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," Washington, DC: U.S. Nuclear Regulatory Commission, 2021. 10 CFR Part 50-TN249

ASME Code, Section III, Mandatory Appendix XXVI – Rules for Construction of Class 3 Buried Polyethylene Piping. ASME 2021-TN10989

AWWA. C105, "Polyethylene Encasement for Ductile-Iron Pipe Systems," Denver, Colorado: American Water Works Association, 2010. AWWA 2010-TN9462

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. EPRI 2010-TN9463

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. ISO 2003-TN9464

NRC Generic Letter 89-13, "Service Water Systems Problems Affecting Safety Related Equipment." NRC 1989-TN9367

NRC Generic Letter 89-13, "Service Water Systems Problems Affecting Safety Related Equipment," Supplement 1. A NRC 1990-TN9368

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) (TN249), 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 (NRC 2006-TN9496), 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 (NRC 1992-TN9487), “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.

[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.

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 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:

a. components that are outside the boundaries of the containment, as defined in the plant-specific design specification

b. embedded or inaccessible portions of containment components that met the requirements of the original construction code of record

c. 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

d. 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 [EPRI 1987-TN9122, EPRI 1990-TN9123] and TR-104213 [EPRI 2000-TN8054]), 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,” (RCSC 2020-TN10990) 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 (EPRI 1998-TN9438) 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 (NRC 1987-TN9479), “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 (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 action element of this AMP for both safety-related and non-safety-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 (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 non-safety-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 (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 non-safety-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 (TN249), Appendix J and adhoc inspections conducted by licensees and the NRC. NRC IN 86-99 (NRC 1986-TN9480, NRC 1991-TN9481), IN 88-82 (NRC 1988-TN9482, NRC 1989-TN9483), IN 89-79 (NRC 1989-TN9485, NRC 1990-TN9486), IN 2004-09 (NRC 2004-TN9489), IN 2010-12 (NRC 2010-TN9491), NUREG-1522 (NRC 1995-TN8220), and NUREG/CR-7111 (NRC 2012-TN8216) described occurrences of corrosion in steel containment shells, containment liners, and tori. NRC GL 87-05 (NRC 1987-TN9479) addressed the potential for corrosion of BWR Mark I steel drywells in the "sand pocket region." IN 2011-15 (NRC 2011-TN9492) described occurrences of corrosion in BWR Mark I steel containments, both inside the suppression chamber (torus) and outside the drywell. IN 2014-07 (NRC 2014-TN9493) 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 (NRC 1997-TN9488) identified specific locations where concrete containments are susceptible to liner plate corrosion; IN 92-20 (NRC 1992-TN9487) 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 (NRC 1997-TN9495) (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" (NRC 2011-TN9497) 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 (NRC 1995-TN8220) and Enclosure 2 to NRC Inspection Progress Report 05000302/2011009 dated May 12, 2011 (NRC 2011-TN9494).

NRC IN 2006-01 (NRC 2006-TN9490) 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 (TN249), augmented to consider OE, and as recommended in LR-ISG-2006-01 (NRC 2006-TN9496), 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 1982-TN8349), NRC GL 91-17) (NRC 1991-TN8357). SCC has occurred in high-strength bolts used for nuclear steam supply system component supports (EPRI NP-5769) (EPRI 1988-TN8108).

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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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

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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 1987-TN9122 and EPRI 1990-TN9123

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_____. Information Notice 88-82, “Torus Shells with Corrosion and Degraded Coatings in BWR Containments.” ADAMS Accession Nos. ML031150069, ML082910476. Washington, DC:

[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.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 (NRC 2012-TN8217), "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) (TN249) 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 (ACI 2008-TN9143) and ACI 349.3R (ACI 2002-TN9327). 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 (ACI 2008-TN9143). 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 (ACI 2002-TN9327) 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 (TN249) 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 (NRC 1990-TN8125), "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 (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 non-safety-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 non-safety-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 non-safety-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 (TN249) 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 (NRC 1995-TN8220), "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 (NRC 1999-TN8126), 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 (TN249), is a necessary element of aging management for concrete containments through the subsequent period of extended operation.

NRC Inspection Report 05000302/2009007 (NRC 2010-TN8219) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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

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_____. Information Notice 2010-14, “Containment Concrete Surface Condition Examination Frequency and Acceptance Criteria.” ADAMS Accession No. ML101600151. Washington, DC: U.S. Nuclear Regulatory Commission. August 2010. NRC 2010-TN8218

_____. Inspection Report, Crystal River Nuclear Plant – Special Inspection Report 05000302/2009007. ADAMS Accession No. ML102861026. Washington, DC: U.S. Nuclear Regulatory Commission. October 12, 2010. NRC 2010-TN8219

_____. NUREG–1522, “Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1995. NRC 1995-TN8220

[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. NRC 1990-TN8125

_____. Regulatory Guide 1.90, “Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons.” ADAMS Accession No. ML11249A008. Washington, DC: U.S. Nuclear Regulatory Commission. November 2012. NRC 2012-TN8217

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 [EPRI 1987-TN9122, EPRI 1990-TN9123] and EPRI TR–104213 [EPRI 2000-TN8054]), 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,” (RCSC 2020-TN10990) 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 of 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:

a. deformations or structural degradations of fasteners, springs, clamps, or other support items

b. missing, detached, or loosened support items, including bolts and nuts

c. arc strikes, weld spatter, paint, scoring, roughness, or general corrosion on close tolerance machined or sliding surfaces

d. improper hot or cold positions of spring supports and constant load supports

e. misalignment of supports

f. improper clearances of guides and stops

Other unacceptable conditions include:

a. loss of material due to corrosion or wear

b. debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support

c. cracked or sheared bolts, including high-strength bolts, and anchors

d. loss of material, cracking, and hardening of elastomeric or polymeric vibration isolation elements that could reduce the vibration isolation function

e. 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 non-safety-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, or tested, or 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 (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 non-safety-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 non-safety-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 (NRC 1982-TN8349), "Degradation of Threaded Fasteners In the Reactor Coolant Pressure Boundary of PWR Plants," NRC Generic Letter 91-17 (NRC 1991-TN8357), "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) (EPRI 1988-TN8108). NRC Information Notice 2009-04 (NRC 2009-TN9499) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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, Subsection IWB, Requirements for Class 1 Components of Light-Water Cooled Power Plants.” New York, New York: The American Society of Mechanical Engineers. 2008.[2] ASME 2008-TN8166

_____. ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWC, Requirements for Class 2 Components of Light-Water Cooled Power Plants.” New York, New York: The American Society of Mechanical Engineers. 2008. ASME 2008-TN8166

_____. ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWD, Requirements for Class 3 Components of Light-Water Cooled Power Plants.” New York, New York: The American Society of Mechanical Engineers. 2008. ASME 2008-TN8166

_____. 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. ASME 2008-TN8166

_____. ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWF, Requirements for Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants.” New York, New York: The American Society of Mechanical Engineers. 2008. ASME 2008-TN8166

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 1987-TN9122 and EPRI 1990-TN9123

_____. EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants.” Volumes 1 and 2. Palo Alto, California: Electric Power Research Institute. April 1988. EPRI 1988-TN8108

_____. EPRI TR–104213, “Bolted Joint Maintenance & Application Guide.” Palo Alto, California: Electric Power Research Institute. December 1995. EPRI 2000-TN8054

[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.

NRC. Generic Letter 91-17, “Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants.” Agencywide Documents Access and Management System (ADAMS) Accession No. ML031140534. Washington, DC: U.S. Nuclear Regulatory Commission. October 1991. NRC 1991-TN8357

_____. IE Bulletin 82-02, “Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants.” ADAMS Accession No. ML03120720. Washington, DC: U.S. Nuclear Regulatory Commission. June 1982. NRC 1982-TN8349

_____. Information Notice 2009-04, “Age-Related Constant Support Degradation.” ADAMS Accession No. ML090340754. Washington, DC: U.S. Nuclear Regulatory Commission. February 2009. NRC 2009-TN9499

RCSC. “Specification for Structural Joints Using High-Strength Bolts.” Chicago, Illinois: Research Council on Structural Connections. June 2020. RCSC 2020-TN10990

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 (TN249), 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 (TN249), 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 (NRC 1995-TN9504), "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 (TN249), Appendix J, as approved by the NRC final safety evaluation for NEI 94-01, Revision 2-A (NEI 2008-TN9500) and Revision 3-A (NEI 2012-TN9501), provide additional information regarding Option B. Three types of tests 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 information would be acquired 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 (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 non-safety-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 (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 non-safety-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 non-safety-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 (NRC 1992-TN9487), "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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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 2008-TN8166

_____. 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. ASME 2008-TN8166

[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 2008-TN9500

_____. 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. NEI 2012-TN9501

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. EPRI 2007-TN9502

_____. “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. NRC 2008-TN9503

_____. Information Notice 92-20, “Inadequate Local Leak Rate Testing.” ADAMS Accession No. ML031200473. Washington, DC: U.S. Nuclear Regulatory Commission. March 1992. NRC 1992-TN9487

_____. 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. NRC 1995-TN9504

XI.S5 MASONRY WALLS

Program Description

The U.S. Nuclear Regulatory Commission (NRC) Inspection and Enforcement Bulletin (IEB) 80-11 (NRC 1980-TN9506), "Masonry Wall Design," and NRC Information Notice (IN) 87-67 (NRC 1987-TN9507), "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 non-safety-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 (NRC 1980-TN9506) 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 (NRC 1980-TN9506) and NRC IN 87-67 (NRC 1987-TN9507), 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 attributes of the 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 (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 non-safety-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 (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 non-safety-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 non-safety-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 1980-TN9506), NRC Generic Letter 87-02 (NRC 1987-TN9505), and 10 CFR 50.48 (TN249). NRC IN 87-67 (NRC 1987-TN9507) 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 (NRC 1995-TN8220) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." 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. 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. NRC 1987-TN9505

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_____. 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. NRC 1995-TN8220

XI.S6 STRUCTURES MONITORING

Program Description

Implementation of structures monitoring under Title 10 of the *Code of Federal Regulations* (10 CFR) 50.65 (TN249) (the Maintenance Rule) is addressed in the U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.160 (NRC 2012-TN9515), and Nuclear Management and Resources Council 93-01 (NEI 2011-TN9509). 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 2002-TN9327), ACI 201.1R (ACI 2008-TN9143), 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 2002-TN9327), 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 (NRC 1978-TN8135), “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 [EPRI 1987-TN9122, EPRI 1990-TN9123] and TR-104213 [EPRI 2000-TN8054]), 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,” (RCSC 2020-TN10990) 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 (ACI 2002-TN9327) 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 (NRC 2012-TN9515). 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 (ACI 2002-TN9327) 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/or 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 and/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 and/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 2002-TN9327), 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 (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 non-safety-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 (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 non-safety-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 non-safety-related SCs within the scope of this program.

10 ***Operating Experience:*** NUREG-1522 (NRC 1995-TN8220) 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 (NRC 2011-TN9513) discusses an instance of groundwater infiltration leading to alkali-silica reaction degradation in below-grade concrete structures, while IN 2004-05 (NRC 2004-TN9511) and IN 2006-13 (NRC 2006-TN9512) discusses instances of through-wall water leakage from spent fuel pools. NUREG/CR-7111 (NRC 2012-TN8216) 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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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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AISC. “AISC Specification for Steel Buildings.” Chicago, Illinois: American Institute of Steel Construction, Inc. 2005. ANSI/AISC 2005-TN9508

ASCE. SEI/ASCE 11-99, “Guideline for Structural Condition Assessment of Existing Buildings.” Reston, Virginia: American Society of Civil Engineers. 2000. SEI/ASCE 2000-TN9510

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 1987-TN9122 and EPRI 1990-TN9123

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_____. Regulatory Guide 1.127, “Inspection of Water-Control Structures Associated With Nuclear Power Plants.” Revision 1. ADAMS Accession No. ML003739392. Washington, DC: U.S. Nuclear Regulatory Commission. 1978. NRC 1978-TN8135

_____. Regulatory Guide 1.142, “Safety-Related Concrete Structures for Nuclear Power Plants (Other than Reactor Vessels and Containments).” Revision 2. ADAMS Accession No. ML013100274. Washington, DC: U.S. Nuclear Regulatory Commission. 2001. NRC 2001-TN9514

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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 attributes of program elements 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 [EPRI 2000-TN8054]), 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,” (RCSC 2020-TN10990) 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 (ACI 2008-TN9143) and ACI 349.3R (ACI 2002-TN9327). 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 (ACI 2002-TN9327) 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 (ACI 2002-TN9327) 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 (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 non-safety-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 (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 non-safety-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 non-safety-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 (NRC 1995-TN8220), "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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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 2008-TN9143

_____. ACI Standard 349.3R-02, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.” Farmington Hills, Michigan: American Concrete Institute. 2002. ACI 2002-TN9327

AISC. “AISC Specification for Steel Buildings.” Chicago, Illinois: American Institute of Steel Construction, Inc. 2010. ANSI/AISC 2010-TN9516

ASCE. SEI/ASCE 11-99, “Guideline for Structural Condition Assessment of Existing Buildings.” Reston, Virginia: American Society of Civil Engineers. 2000. SEI/ASCE 2000-TN9510

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 1987-TN9122 and EPRI 1990-TN9123

____. EPRI TR–104213, “Bolted Joint Maintenance & Application Guide.” Palo Alto, California: Electric Power Research Institute. December 1995. EPRI 2000-TN8054

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. NRC 1995-TN8220

_____. Regulatory Guide 1.127, “Inspection of Water-Control Structures Associated With Nuclear Power Plants.” ADAMS Accession No. ML003739392. Washington, DC: U.S. Nuclear Regulatory Commission. March 1978. NRC 1978-TN8135

_____. 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. NRC 1993-TN9517

RCSC. “Specification for Structural Joints Using High-Strength Bolts.” Chicago, Illinois: Research Council on Structural Connections. June 2020. RCSC 2020-TN10990

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 License Renewal [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 (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 non-safety-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 (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 non-safety-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 non-safety-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 AND SUPPORTING DOCUMENTS

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2021. 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 2005-TN9518

_____. 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 2008-TN9519

_____. 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. ASTM 1996-TN9520

EPRI. EPRI 1003102, “Guideline on Nuclear Safety-Related Coatings.” Revision 1. (Formerly TR-109937). Palo Alto, California: Electric Power Research Institute. November 2001. EPRI 2001-TN9521

_____. EPRI 1019157, “Guideline on Nuclear Safety-Related Coatings.” Revision 2. (Formerly TR-109937and 1003102). Palo Alto, California: Electric Power Research Institute. December 2009. EPRI 2009-TN9476

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. NRC 1996-TN9522

_____. Generic Letter 04-02, “Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. September 2004. NRC 2004-TN9523

_____. 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. NRC 1998-TN9524

_____. Information Notice 88-82, “Torus Shells with Corrosion and Degraded Coatings in BWR Containments.” Washington, DC: U.S. Nuclear Regulatory Commission. November 1988. NRC 1988-TN9482

_____. Information Notice 97-13, “Deficient Conditions Associated With Protective Coatings at Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1997. NRC 1997-TN9525

_____. 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. AEC 1973-TN9528

_____. 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. NRC 2000-TN9526

_____. 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. NRC 2010-TN9468

_____. 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. NRC 2017-TN9527

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging 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.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
XI.E3A	Electrical Insulation for Inaccessible Medium-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) medium-voltage power cable (operating voltage; 2 kV to 35 kV) within the 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.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent 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, 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.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
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 (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.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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 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.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
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 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 2014-TN8110) (EPRI 3002002623, BWR Water Chemistry Guidelines – 2014 Revision) for	The program is implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		boiling water reactors (BWRs) or (2) EPRI 3002000505 (EPRI 2014-TN8111) (PWR Primary Water Chemistry – Revision 7) and EPRI 3002010645 (EPRI 2017-TN8112) (PWR Secondary Water Chemistry – Revision 8) for pressurized water reactors (PWRs).	
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 (NRC 2010-TN8358). 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 (EPRI 2004-TN8359), "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 in BWRVIP-48-A (EPRI 2004-TN8359). Crack growth evaluations follow the guidance in BWRVIP-14-A (EPRI 2008-TN8301), "Evaluation of Crack Growth in BWR Stainless Steel RPV Internals, dated September 2008; BWRVIP-59-A (EPRI 2007-TN8312), "Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals," dated May 2007; or BWRVIP-60-A (EPRI 2003-TN8313), "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 (EPRI 2004-TN8359) and ASME Code, Section XI, Subarticle IWB-3520. Repair and replacement activities are conducted in accordance with	The program is implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		BWRVIP-52-A (EPRI 2005-TN8311), "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 (EPRI 2005-TN8362). 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) 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 (EPRI 2002-TN8368), BWRVIP-47-A (EPRI 2004-TN8309) and BWRVIP-27-A (EPRI 2003-TN8367) 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 program is implemented 6 months prior to 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-	The program is implemented 6 months prior to the subsequent period

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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. 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.	of extended operation.
XI.M10	Boric Acid Corrosion	This program relies, in part, on the response to NRC GL 88-05 (NRC 1988-TN9189), “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	The program is implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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” (WEC 2012-TN10977).	
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 (ASME 2009-TN10979), 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 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.	The program is implemented 6 months prior to the subsequent period of extended operation.
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	The program is implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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.	
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) (EPRI 2018-TN9218) 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. 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.]	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 period of extended operation.
XI.M17	Flow-Accelerated Corrosion (FAC)	This program is based on the response to NRC GL 89-08 (NRC 1989-TN8046), "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,	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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.	
XI.M18	Bolting Integrity	This program focuses on closure bolting for pressure-retaining components and relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339 (NRC 1990-TN8053) 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 (EPRI 2007-TN9254) and 1015337 (EPRI 2007-TN9255). 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 non-safety-related closure bolting and supplements this bolting integrity program. Other related programs, AMPs XI.S1, “ASME	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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 non-safety-related structural bolting.	
XI.M19	Steam Generators	This program manages the aging of steam generator tubes, plugs, sleeves, divider plate assemblies, 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, 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 (NEI 2011-TN9268), 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.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
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 non-safety-related portions of the open-cycle cooling water system]. The program includes	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		(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.	of extended operation.
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 (EPRI 2013-TN9378), “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 (NRC 1980-TN9395), 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.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
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 (NRC 1998-TN9405) and the Institute of Nuclear Power Operations' Significant Operating Experience Report 88-01 (INPO 1988-TN10981). 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)-7.0.1-1996, and EPRI TR–10847 for testing and monitoring air quality and moisture. Additionally, periodic visual inspections of component internal surfaces are performed to detect signs of loss of material due to corrosion.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
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 (NRC 1988-TN8039), 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	The program is implemented and inspections or tests begin within the 5-year period before the subsequent period of extended

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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 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.	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 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

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

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.	operation or no later than the last 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 prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
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 (TN249), 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, these should be reinserted so that appropriate lead factors are maintained and test results will bound the corresponding operating period. 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.	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.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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 (TN249), 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 analysis 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. 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	

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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 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.	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. Structures and components should be inspected only after an incubation period of sufficient 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.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
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 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 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.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	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

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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.	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 Mechanical Components	This program is a condition monitoring program that manages the loss of material, cracking, changes in material properties (of cementitious components), hardening or loss 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	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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.	
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 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.”	Program and SLR enhancements, when applicable, are implemented 6 months prior to 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,	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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 service, and severity of operating conditions. 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 in-leakage and corrosion product buildup.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
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.
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	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	The program is implemented and inspections begin within the 10-year period before the subsequent period

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
	Exchangers, and Tanks	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 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 non-cementitious 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.	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.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
XI.M43	High-Density Polyethylene (HDPE) Piping and Carbon Fiber-Reinforced Polymer (CFRP) Repaired Piping	This program manages the aging effects associated with the internal and external 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.	This program is implemented and 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 of thickness due to

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

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.	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 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	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 operation, and are to be completed prior to the subsequent period of extended operation, are

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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.	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 (TN249) 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 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,	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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-watercontrol 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 ensure post-accident operability of the Emergency Core Cooling System.	Program and SLR enhancements, when applicable, are implemented 6 months prior to the subsequent period of extended operation.
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	The program is implemented 6 months prior to the subsequent period of extended operation.

Table XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs (Continued)

AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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.	

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.

CHAPTER XII

REFERENCES

REFERENCES

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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 non-safety-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 (TN249) 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 (TN249), 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 non-safety-related SCs subject to an AMR for SLR, the AMPs applicable to non-safety-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 non-safety-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 (TN249), 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 (TN249), 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 non-safety-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 (TN249), 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 (TN249), 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 appropriate, when it is determined through these evaluations that the effects of aging	The program and necessary enhancements are implemented no later than the date the subsequently renewed operating license is issued.

Table B-01 FSAR Supplement Summary for Operating Experience Programs for Aging Management Programs (Continued)

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule
		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.

APPENDIX C

DISPOSITION OF PUBLIC COMMENTS ON THE DRAFT SUBSEQUENT LICENSE RENEWAL GUIDANCE DOCUMENTS NUREG-2191, NUREG-2192, AND NUREG-2221

DISPOSITION OF PUBLIC COMMENTS ON THE DRAFT SUBSEQUENT LICENSE RENEWAL GUIDANCE DOCUMENTS NUREG-2191, NUREG-2192, AND NUREG-2221

C.1 EXECUTIVE SUMMARY

Public comment drafts of the NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," Volumes 1 and 2, Revision 1 (GALL-SLR Report, Revision 1); NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants," Revision 1 (SRP-SLR, Revision 1); and NUREG-2221, "Technical Bases for Changes in the Subsequent License Renewal Guidance Documents, NUREG–2191, Revision 1, and NUREG-2192, Revision 1," Supplement 1 (Technical Bases Document, Supplement 1), were published on July 11, 2023, with the public comment period expiring on October 11, 2023. The disposition of comments that were agreed with by the U.S. Nuclear Regulatory Commission (NRC) staff and used as the basis for instituting a change to the GALL-SLR Report, Revision 1, SRP-SLR, Revision 1, or the Technical Bases Document, Supplement 1, are detailed in this appendix. In addition, the public comments that did not result in a change to any of the NUREGs are also dispositioned here, and the NRC staff's technical basis for not agreeing with these comments is presented. Many public comments resulted in changes to the GALL-SLR Report and the SRP-SLR. Some of the changes to the SRP-SLR were derived from the changes to the GALL-SLR Report.

C.1.1 Public Comment Overview

On July 11, 2023 (88 FR 44160), the NRC issued for public comment the following draft NUREGs that provide revised guidance for subsequent license renewal (SLR) and the associated technical bases for the revised guidance documents:

- Draft GALL-SLR Report, Volume 1, Revision 1, ADAMS Accession No. ML23180A182
- Draft GALL-SLR Report, Volume 2, Revision 1, ADAMS Accession No. ML23180A188
- Draft SRP-SLR, Revision 1, ADAMS Accession No. ML23180A191
- Draft Technical Bases Document, Supp. 1, ADAMS Accession No. ML23180A208

The draft revisions incorporated changes that reflected past precedents and other lessons learned since Revision 2 of NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," and NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," published in 2010.

In addition to issuing the draft revisions of these SLR guidance documents for formal public comment, the NRC staff held several public meetings with stakeholders to discuss the content of the draft SLR guidance and subsequent comments on these draft documents. Following is a list of the public meetings along with their associated meeting summaries:

- June 1, 2022, ADAMS Accession No. ML22160A291
- September 7–8, 2022, ADAMS Accession No. ML22271A348
- August 21–22, 2023, ADAMS Accession No. ML23279A147
- May 23, 2024, ADAMS Accession No. ML24313A011

- June 18, 2024, ADAMS Accession No. ML24178A036

In response to a request to extend the comment period dated August 25, 2023, (ADAMS Accession No. ML23242A214), the NRC staff extended the public comment period to October 11, 2023 (88 FR 61628). The NRC staff took into consideration the comments received as a result of the formal solicitation described above and incorporated its dispositions into the final versions of the SLR guidance documents. This appendix provides the evaluation and disposition of public comments received by the NRC on the draft revisions of the SLR guidance.

C.1.2 Technical Bases Overview

NUREG-2221, Revision 0, "Technical Bases for Changes in the Subsequent License Renewal Guidance Documents NUREG-2191 and NUREG-2192," (ADAMS Accession No. ML17362A126) (or Initial Report) provides a summary of changes and a synopsis of the bases for these changes made as part of the development of the SRP-SLR, Revision 0, and the GALL-SLR Report, Revision 0.

Similarly, NUREG-2221, Supplement 1, "Technical Bases for Changes in the Subsequent License Renewal Guidance Documents NUREG-2191 and NUREG-2192," provides a summary of changes and a synopsis of the bases for these changes made as part of the updating SLR guidance into the SRP-SLR, Revision 1, and the GALL-SLR Report, Revision 1.

These changes include those that were initiated by NRC staff as well as the changes made in response to public comments, as appropriate. These documents provide the underlying rationale that the NRC used in updating the SLR guidance.

C.1.3 Purpose and Organization of the Appendix

NUREG-2222, "Disposition of Public Comments on the Draft Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG-2192," contains the NRC staff's analysis and responses of the public comments received on the drafts of Revision 0 of NUREG-2191, NUREG-2192, and NUREG-2221.

This appendix serves the same purpose as NUREG-2222, as it contains the NRC staff's analysis and responses of the public comments received on the drafts of Revision 1 of NUREG-2191 and NUREG-2192, and Supplement 1 of NUREG-2221.

This appendix is organized into three sections:

- Appendix Section C.1, "Executive Summary," contains background and overview information.
- Appendix Section C.2, "Analysis and Disposition of Public Comments on the July 2023 Public Comment Draft Guidance Documents for Subsequent License Renewal," summarizes the analysis and disposition of all public comments received on the draft of the GALL-SLR Report, SRP-SLR, and Technical Bases during the public comment period and received on the Regulations.gov Docket NRC-2023-0096.
- Appendix Section C.3, "Draft NUREG-2191 Volume 1, NUREG -2192 Volume 2, and NUREG-2221 Supplement 1, Public Comments and Responses," contains a summary of each public comment, staff responses, and an overview of document changes.

C.2 ANALYSIS AND DISPOSITION OF PUBLIC COMMENTS ON THE JULY 2023 PUBLIC COMMENT DRAFT GUIDANCE DOCUMENTS FOR SUBSEQUENT LICENSE RENEWAL

C.2.1 Public Comment Solicitation and Management

Following the publication of the draft SLR Guidance documents, the NRC staff conducted public meetings on August 21, 2023, August 22, 2023, May 23, 2024, and June 18, 2024, to initiate a dialogue with the public and to introduce to them some of the significant changes within the guidance documents. The purpose of the public meetings was to provide:

- an opportunity for the staff to inform the public about the draft GALL-SLR Report and SRP-SLR NUREGs
- an opportunity for an exchange of information about the draft NUREGs
- an opportunity for stakeholders to ask questions about the draft NUREGs
- a forum for stakeholders to provide informal feedback on the drafts

The NRC staff was particularly interested in comments that addressed the safety review, effectiveness, and efficiency of the future SLR process. Formal comments on the draft NUREGs and the supplement were to be provided through means identified in the *Federal Register* (e.g., written letter and submittal to Regulations.gov). Comments during the public meetings were not accepted as formal comments. The NRC staff anticipated that some topics would not be discussed fully due to time limitations.

C.2.2 Disposition of Public Comments on the July 2023 Draft GALL-SLR Report, SRP-SLR, and the Technical Bases

All formal public comments were submitted and received by the NRC staff via Regulations.gov. The comments were collected, entered into the Agencywide Documents Access and Management System (ADAMS), tabulated, and categorized whether they related to the initial SLR Guidance NUREGs, Revision 0, or revised draft SLR Guidance, Revision 1. The comments were binned and assigned to the subject matter experts who would be addressing the comments.

Over 140 pages of public comments were received on the draft GALL-SLR Report, Volume 1, Revision 1, GALL-SLR Report, Volume 2, Revision 1, SRP-SLR, Revision 1, and Technical Bases Document, Supplement 1. The NRC staff reviewed each comment and prepared responses, which are listed in Appendix Section C.3.

All of the public comments on the July 2023 Draft GALL-SLR Report, Revision 1, Volume 1 and Volume 2, Draft SRP-SLR, Revision 1, and Draft Technical Bases Document, Supplement 1, that were received are presented in the pages that follow. The comments are organized by comment submitter and presented in the order that they appeared in Regulations.gov, except for when the staff has consolidated comments for providing an efficient response. Each comment has a unique NRC ID Number, which is used to identify and present each comment in order, except for when the staff has consolidated comments for providing an efficient response, in Appendix Section C.3. An overview of the comment along with any rationale or justification provided by the commenter, is summarized. This is followed by the NRC staff's disposition of each comment, whether the staff agreed or disagreed with the comment, and an explanation of why the NRC staff agreed with the comment and implemented recommended changes,

or disagreed with the comment. Finally, the NRC staff describes any changes it made to the relevant documents based on the comment.

Table C-1, “Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers,” of this appendix provides the reader a summary and crosswalk, including the comment source, the comment subject, the ADAMS Accession Number, the Regulations.gov Comment ID, and the unique NRC ID Numbers for all public comments received.

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
William Weitze	X.M1, “Fatigue Monitoring reference updates, RG 1.207, Revision 1 and NUREG/CR-6909, Revision 1.	ML23236A517	NRC-2023-0096-0007	1
Michael Gallagher	Eliminate One Time Inspections of the XI.M2, “Water Chemistry;” XI.M30, “Fuel Oil Chemistry;” and XI.M39, “Lubricating Oil Analysis;” programs.	ML23242A043	NRC-2023-0096-0009	3
Michael Gallagher	XI.M3, “Reactor Head Closure Stud Bolting,” preventative action.	ML23242A046	NRC-2023-0096-0010	4
Michael Gallagher	XI.M17, “Flow-Accelerated Corrosion,” exclusion from wall thickness monitoring for piping systems.	ML23242A047	NRC-2023-0096-0011	5
Michael Gallagher	XI.M18, “Bolting Integrity,” eliminating prescriptive corrective actions.	ML23242A048	NRC-2023-0096-0012	6
Michael Gallagher	Eliminating prescriptive corrective actions for several Aging Management Programs (AMPs).	ML23242A049	NRC-2023-0096-0013	7
Michael Gallagher	XI.M21A, “Closed Treated Water Systems,” eliminating prescriptive corrective actions.	ML23242A051	NRC-2023-0096-0014	8
Michael Gallagher	XI.M27, “Fire Water System,” eliminating prescriptive corrective actions.	ML23242A053	NRC-2023-0096-0015	9
Michael Gallagher	XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” eliminating prescriptive corrective actions.	ML23242A054	NRC-2023-0096-0016	10
Michael Gallagher	XI.M30, “Fuel Oil Chemistry,” eliminate One Time Inspections	ML23242A056	NRC-2023-0096-0017	11
Michael Gallagher	Eliminate One Time Inspections of the XI.M2, “Water Chemistry;” XI.M30, “Fuel Oil Chemistry;” and XI.M39, “Lubricating Oil Analysis;” AMPs.	ML23242A057	NRC-2023-0096-0018	12
Michael Gallagher	XI.M33, “Selective Leaching,” eliminating prescriptive corrective actions	ML23242A059	NRC-2023-0096-0019	13
Michael Gallagher	XI.M35, “ASME Code Class 1 Small-Bore Piping,” “no history” operating experience.	ML23242A060	NRC-2023-0096-0020	14
Michael Gallagher	XI.M36, “External Surfaces Monitoring Of Mechanical Components,” eliminating prescriptive corrective actions.	ML23242A062	NRC-2023-0096-0021	15
Michael Gallagher	XI.M38, “Inspection Of Internal Surfaces In Miscellaneous Piping and Ducting Components,” eliminating prescriptive corrective actions.	ML23242A065	NRC-2023-0096-0022	16
Michael Gallagher	XI.M39, “Lubricating Oil Analysis,” eliminate One Time Inspections.	ML23242A066	NRC-2023-0096-0023	17

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Michael Gallagher	XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," eliminating prescriptive corrective actions.	ML23242A068	NRC-2023-0096-0024	18
Michael Gallagher	XI.S6, "Structures Monitoring," change inspection frequency.	ML23242A070	NRC-2023-0096-0025	19
Michael Gallagher	Reduction of NRC staff review time for SLR applications using existing corrective action programs, operating experience program, and targeted scope and screening.	ML23242A071	NRC-2023-0096-0026	20
Michael Gallagher	Reduction of NRC staff review time for SLR applications, generic reviews with SRP-SLR branch technical positions and operating experience for AMPs.	ML23242A073	NRC-2023-0096-0027	21
Michael Gallagher	XI.M32, "One-Time Inspection," Element 4, Detection of Aging Effects, one-time inspection should be performed after sufficient operational exposure	ML23262A744	NRC-2023-0096-0029	22
Michael Gallagher	Inspection samples are taken from multiple locations, related to several AMPs.	ML23262A745	NRC-2023-0096-0030	23
Michael Gallagher	XI.M43 High-Density Polyethylene (HDPE) Piping and Carbon Fiber-Reinforced Polymer (CFRP) Repaired Piping eliminating prescriptive corrective actions.	ML23262A746	NRC-2023-0096-0031	24
Michael Gallagher	Deletion XI.M43 High-Density Polyethylene (HDPE) Piping and Carbon Fiber-Reinforced Polymer (CFRP) Repaired Piping.	ML23262A748	NRC-2023-0096-0032	25
Michael Gallagher	NRC technical staff use of industry Operating Experience.	ML23272A001	NRC-2023-0096-0033	26
Tina Taylor (Electric Power Research Institute [EPRI])	Correction of typo, in NUREG-2191, Volume 1, Chapter II.A, Chapter Title:	ML23284A377	NRC-2023-0096-0036	29-001
Tina Taylor (EPRI)	Aging Management Review (AMR) item IV.B2.RP-285, material stellite for insert wear surfaces.	ML23284A377	NRC-2023-0096-0036	29-002
Tina Taylor (EPRI)	AMR item IV.B2.RP-285, Aging Effect/Mechanism.	ML23284A377	NRC-2023-0096-0036	29-003
Tina Taylor (EPRI)	AMR item IV.B2.RP-302 Aging Effect/Mechanism.	ML23284A377	NRC-2023-0096-0036	29-004

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Tina Taylor (EPRI)	AMR items VII.C1.AP-239, VII.C1.A-739, and VII.G.A-648, Aging Effect/Mechanism.	ML23284A377	NRC-2023-0096-0036	29-005
Tina Taylor (EPRI)	Deleting “loss of material due to exposure to temperature or moisture” from the list of aging effects / mechanisms in HDPE AMR line items VII.I.AP-175, VII.I.A-406, and VII.G.A-648.	ML23284A377	NRC-2023-0096-0036	29-006
Tina Taylor (EPRI)	Deletion of “moisture” from Aging Effect/Mechanism mechanisms for CFRP AMR items VII.I.AP-182, VII.I.A-420, and VII.I.A-538.	ML23284A377	NRC-2023-0096-0036	29-007
Tina Taylor (EPRI)	AMP XI.E1, “Electrical Insulation for Electrical Cables and Connections Not Subject To 10CFR 50.49 Environmental Qualification Requirements,” program description.	ML23284A377	NRC-2023-0096-0036	29-008
Tina Taylor (EPRI)	AMP XI.E1,"Electrical Insulation for Electrical Cables and Connections Not Subject To 10CFR 50.49 Environmental Qualification Requirements,” Element 4, fire-retardant material.	ML23284A377	NRC-2023-0096-0036	29-009
Tina Taylor (EPRI)	AMP XI.E3A, “Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” Program Description.	ML23284A377	NRC-2023-0096-0036	29-010
Tina Taylor (EPRI)	XI.M4, “BWR Attachment Welds,” reference to ASME Code Case N-896.	ML23284A377	NRC-2023-0096-0036	29-011
Tina Taylor (EPRI)	XI.M7, “BWR Stress Corrosion Cracking,” reference to ASME Code Case N-896.	ML23284A377	NRC-2023-0096-0036	29-012
Tina Taylor (EPRI)	XI.M8, “BWR Penetrations,” reference to ASME Code Case N-896.	ML23284A377	NRC-2023-0096-0036	29-013
Tina Taylor (EPRI)	XI.M8, “BWR Penetrations,” reference to EPRI. BWRVIP-190 Revision 1.	ML23284A377	NRC-2023-0096-0036	29-014
Tina Taylor (EPRI)	XI.M9, “BWR Vessel Internals,” reference to BWRVIP-100, Revision 1-A.	ML23284A377	NRC-2023-0096-0036	29-015
Tina Taylor (EPRI)	XI.M9, “BWR Vessel Internals,” reference to BWRVIP-180. BWRVIP-180, Revision 1.	ML23284A377	NRC-2023-0096-0036	29-016
Tina Taylor (EPRI)	XI.M9, “BWR Vessel Internals,” EPRI. BWRVIP-190 Revision 1.	ML23284A377	NRC-2023-0096-0036	29-017
Tina Taylor (EPRI)	XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel,” ferrite content.	ML23284A377	NRC-2023-0096-0036	29-018
Tina Taylor (EPRI)	XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel,” reference to NUREG/CR-4513.	ML23284A377	NRC-2023-0096-0036	29-019
Tina Taylor (EPRI)	AMP XI.M17, “Flow-Accelerated Corrosion,” reference to EPRI 3002023786.	ML23284A377	NRC-2023-0096-0036	29-020

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Tina Taylor (EPRI)	AMP XI.M17, "Flow-Accelerated Corrosion," exclusion criterion per EPRI 3002023786.	ML23284A377	NRC-2023-0096-0036	29-021
Tina Taylor (EPRI)	AMP XI.M17, "Flow-Accelerated Corrosion," safety factor for erosion.	ML23284A377	NRC-2023-0096-0036	29-022
Tina Taylor (EPRI)	AMP XI.M17, "Flow-Accelerated Corrosion reference to EPRI 3002023786, Revision 1.	ML23284A377	NRC-2023-0096-0036	29-023
Tina Taylor (EPRI)	XI.M33, "Selective Leaching," use of non-destructive examination (NDE) techniques.	ML23284A377	NRC-2023-0096-0036	29-024
Tina Taylor (EPRI)	XI.M33, "Selective Leaching," Elements 4 and 6, visual indicators of selective leaching.	ML23284A377	NRC-2023-0096-0036	29-025
Tina Taylor (EPRI)	XI.M33, "Selective Leaching," addition of EPRI report references.	ML23284A377	NRC-2023-0096-0036	29-026
Tina Taylor (EPRI)	XI.M41, "Buried and Underground Piping and Tanks," Element 4, in-scope piping.	ML23284A377	NRC-2023-0096-0036	29-027
Tina Taylor (EPRI)	XI.M41, "Buried and Underground Piping and Tanks," Element 4, inclusion of alternative inspection approaches for cementitious piping.	ML23284A377	NRC-2023-0096-0036	29-028
Tina Taylor (EPRI)	XI.M41, "Buried and Underground Piping and Tanks," reference to EPRI report 3002018352.	ML23284A377	NRC-2023-0096-0036	29-029
Tina Taylor (EPRI)	XI.M43, "High-Density Polyethylene (HDPE) Piping and Carbon Fiber-Reinforced Polymer (CFRP) Repaired Piping," recommendation to clarify which AMP should be credited with managing effects of aging for buried non-safety-related HDPE and aboveground HDPE piping.	ML23284A377	NRC-2023-0096-0036	29-030
Tina Taylor (EPRI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," recommendation to delete "loss of material due to radiation, temperature, and moisture," on material aging effect/mechanism.	ML23284A377	NRC-2023-0096-0036	29-031
Tina Taylor (EPRI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," technical basis for HDPE and CFRP materials accumulating particulates.	ML23284A377	NRC-2023-0096-0036	29-032
Tina Taylor (EPRI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," recommendation that the program scope address external applications of CFRP.	ML23284A377	NRC-2023-0096-0036	29-033
Tina Taylor (EPRI)	SRP-SLR, Section 3.1.2.2.14, "Loss of Preload Due to Thermal or Irradiation-Enhanced Stress Relaxation," recommendation to revise section to reflect BWRVIP- 25, Revision 1-A on NRC-approved	ML23284A377	NRC-2023-0096-0036	29-034

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
	methodology to justify elimination of core plate holddown bolt inspections.			
Analysis and Measurement Services Corporation (AMS)	XI.E1, “Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” clarification of the definition of adverse localized environment.	ML23284A379	NRC-2023-0096-0037	30-001
AMS	Various electrical AMPs, use of condition monitoring techniques to assess the aged condition of cable insulation materials.	ML23284A379	NRC-2023-0096-0037	30-002
AMS	Various electrical AMPs, clarification of existing maintenance, calibration, or surveillance programs that may be credited in lieu of testing.	ML23284A379	NRC-2023-0096-0037	30-003
AMS	XI.E2, “Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits,” use of insulation resistance testing for detecting age-related degradation of electrical cable insulations.	ML23284A379	NRC-2023-0096-0037	30-004
AMS	Various electrical AMPs, evaluation of the condition of inaccessible electrical cables exposed to significant moisture.	ML23284A379	NRC-2023-0096-0037	30-005
AMS	XI.E1, “Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” Clarification of expectations, which AMPs should be followed, and what actions should be taken for plants that have mostly inaccessible cables.	ML23284A379	NRC-2023-0096-0037	30-006
AMS	XI.E3 A and B AMPs, visual inspection of age-related degradation in cables located in harsh environmental conditions.	ML23284A379	NRC-2023-0096-0037	30-007
AMS	XI.E3 B and C AMPs, periodic testing for evaluating the condition of a cable over time.	ML23284A379	NRC-2023-0096-0037	30-008
AMS	XI.E7, "High Voltage Insulators," Allow for visual inspection alternatives, other test methods demonstrated to be effective in determining the aged condition of insulations.	ML23284A379	NRC-2023-0096-0037	30-009
J. Gromatzky (ENERCON)	Confirm modification of AMR item II.A1.CP-68.	ML23284A380	NRC-2023-0096-0038	31-001
J. Gromatzky (ENERCON)	Confirm modification of AMR item II.A1.CP-32 aging effect/mechanism.	ML23284A380	NRC-2023-0096-0038	31-002

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
J. Gromatzky (ENERCON)	Confirm AMR item II.A1.CP-32 carbonation as an applicable aging mechanism.	ML23284A380	NRC-2023-0096-0038	31-003
J. Gromatzky (ENERCON)	Confirm AMR item II.A1.CP-147 applicable AMP/Time-Limited Aging Analysis (TLAA).	ML23284A380	NRC-2023-0096-0038	31-004
J. Gromatzky (ENERCON)	AMR item II.A1.CP-67 associated table formatting, row breaks across the bottom of pages and column headers.	ML23284A380	NRC-2023-0096-0038	31-005
J. Gromatzky (ENERCON)	Confirm AMR item III.A4.TP-305 environment.	ML23284A380	NRC-2023-0096-0038	31-006
J. Gromatzky (ENERCON)	Confirm AMR item III.A4.T-36 environment.	ML23284A380	NRC-2023-0096-0038	31-007
J. Gromatzky (ENERCON)	Requests for Additional Information on audit comments regarding the use of SRP-SLR and GALL-SLR item numbers from integrated plant assessment (IPA) sections which differ from IPA sections from AMR tables from license renewal applications.	ML23284A380	NRC-2023-0096-0038	31-008
J. Gromatzky (ENERCON)	NRC staff to clearly identify expectations to address items in SLR guidance documents, NUREG-2191 and NUREG-2192, for first time license renewal applicants, in lieu of additional updates to SRP (NUREG-1800) or GALL (NUREG-1801).	ML23284A380	NRC-2023-0096-0038	31-009
J. Gromatzky (ENERCON)	GALL-SLR, Volume 1, Chapter VII, Auxiliary Systems, Table B, “Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems,” the entry for Item VII.B.A-07 contains an editorial error.	ML23284A380	NRC-2023-0096-0038	31-010
J. Gromatzky (ENERCON)	SRP-SLR, Table 3.5-1, “Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR Report)” Item 027, clarification of the AMP column, which indicates AMP XI.S1 “ASME Section XI, Subsection IWE” and AMP XI.S4, “10 CFR Part 50, Appendix J.”	ML23284A380	NRC-2023-0096-0038	31-011
J. Gromatzky (ENERCON)	Recommendation to swap the order of SRP-SLR sections, 3.5.2.2.2.7, “Loss of Material, and/or Changes in Material Properties Due to Weathering, Chemical Degradation, Insect Infestation, Repeated Wetting and Drying, or Fungal Decay,” and 3.5.2.2.2.8, “Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete,” to allow	ML23284A380	NRC-2023-0096-0038	31-012

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
	Group IV "Containment Internal Structures," to flow from one to the other and are not separated by an unrelated further evaluation section.			
J. Gromatzky (ENERCON)	SRP-SLR Section 3.5.2.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete," recommendation to revise further evaluation section as loss of material of carbon or low alloy steel is not associated with irradiation but with a corrosive environment, such as potential boric acid buildup.	ML23284A380	NRC-2023-0096-0038	31-013
Andrew N. Mauer (NEI)	License Renewal Application and Subsequent License Renewal Application future workload necessitates increased efficiency of application reviews, particularly removal of opportunistic inspections, prescriptive actions.	ML23291A071	NRC-2023-0096-0039	32-000
Andrew N. Mauer (NEI)	IX.E, "Aging Effects," removal of cracking as an applicable aging effect for CFRP.	ML23291A071	NRC-2023-0096-0039	32-001
Andrew N. Mauer (NEI)	IX.E, "Aging Effects," removal of flow blockage as an applicable aging effect for CFRP and the reference to delamination or disbonding of CFRP from the flow blockage definition in Table IX.E.	ML23291A071	NRC-2023-0096-0039	32-002
Andrew N. Mauer (NEI)	IX.E, "Aging Effects," removal of the reference to delamination or disbonding of CFRP from the loss of material definition.	ML23291A071	NRC-2023-0096-0039	32-003
Andrew N. Mauer (NEI)	Table G.1, "Fire Protection," AMR item VII.G.A-789 related to steel and stainless steel, stress corrosion cracking (SCC) applies only to stainless steel as described in NUREG-2221, Table 2-10.	ML23291A071	NRC-2023-0096-0039	32-004
Andrew N. Mauer (NEI)	XI.M9 "BWR Vessel Internals," reference to correct EPRI report, replace ML21153A003 with, ML21147A008, EPRI presentation with fracture toughness threshold relative to fluence.	ML23291A071	NRC-2023-0096-0039	32-005
Andrew N. Mauer (NEI)	XI.M9 "BWR Vessel Internals," addition of reference to BWRVIP-58-A, which provides guidelines for Control Rod Drive internal access weld repairs, used for design repairs guidelines.	ML23291A071	NRC-2023-0096-0039	32-006
Andrew N. Mauer (NEI)	XI.M9 "BWR Vessel Internals," revision of reference to BWRVIP-84 to the latest version, revision 3.	ML23291A071	NRC-2023-0096-0039	32-007
Andrew N. Mauer (NEI)	XI.M9 "BWR Vessel Internals," revision of reference to BWRVIP-18 to the latest version, revision 2A.	ML23291A071	NRC-2023-0096-0039	32-008

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Andrew N. Mauer (NEI)	XI.M12 “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel,” revision related to ASME Section XI no longer requires surface examination of valve bodies less than 4 inches NPS.	ML23291A071	NRC-2023-0096-0039	32-009
Andrew N. Mauer (NEI)	XI.M17 “Flow Accelerated Corrosion (FAC),” removal of reference to EPRI 300205530, erosion susceptibility analysis to determine which piping segments should be monitored for erosion through the XI.M17 AMP, which is contrary to the LR-ISG-2012-01 guidance.	ML23291A071	NRC-2023-0096-0039	32-010
Andrew N. Mauer (NEI)	XI.M17 “FAC,” removal of reference to exclusion criteria for erosion, as discussed in LR-ISG-2012-01, erosion is associated with improper operation and is a design issue rather than an aging issue.	ML23291A071	NRC-2023-0096-0039	32-011
Andrew N. Mauer (NEI)	XI.M17 “FAC,” elimination of recommended reassessment of the FAC exclusion criteria for piping lines operating for less than 2% of plant operating time.	ML23291A071	NRC-2023-0096-0039	32-012
Andrew N. Mauer (NEI)	XI.M17 “FAC,” removal of opportunistic inspections whenever components are accessible, FAC program guidance being a very mature program that effectively predicts and monitors FAC in susceptible systems, opportunistic inspections are therefore not warranted.	ML23291A071	NRC-2023-0096-0039	32-013
Andrew N. Mauer (NEI)	XI.M17 “FAC,” removal of the minimum safety factor of 2.0 for erosion mechanisms for evaluating remaining service life of piping where erosion has been identified based on EPRI 3002005530.	ML23291A071	NRC-2023-0096-0039	32-014
Andrew N. Mauer (NEI)	XI.M17 “FAC,” clarification of periodic monitoring guidance for components where erosion is identified and the component is replaced with a more resistant material.	ML23291A071	NRC-2023-0096-0039	32-015
Andrew N. Mauer (NEI)	XI.M18, “Bolting Integrity,” removal of opportunistic inspections whenever components are made accessible from AMP guidance.	ML23291A071	NRC-2023-0096-0039	32-016
Andrew N. Mauer (NEI)	XI.M18, “Bolting Integrity,” removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.	ML23291A071	NRC-2023-0096-0039	32-017
Andrew N. Mauer (NEI)	XI.M18, “Bolting Integrity,” removal of guidance related to cracking of high-strength bolting from various AMPs.	ML23291A071	NRC-2023-0096-0039	32-018
Andrew N. Mauer (NEI)	XI.M2, “Water Chemistry,” removal of references to specific revisions of EPRI Reports 3002002623, 3002000505, and 3002010645 as power plants typically commit to implement the latest water chemistry guidelines.	ML23291A071	NRC-2023-0096-0039	32-019

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Andrew N. Mauer (NEI)	Removal of inspection guidance for the XI.M21A, "Closed Treated Water Systems," AMP, as it relies on control of chemistry parameters and use of corrosion inhibitors and biocides to prevent age-related degradation, and sampling of closed-cycle cooling water for iron and copper content effectively monitors for any unexpected corrosion.	ML23291A071	NRC-2023-0096-0039	32-020
Andrew N. Mauer (NEI)	XI.M21A, "Closed Treated Water Systems," removal of opportunistic inspections whenever components are made accessible from the AMP guidance.	ML23291A071	NRC-2023-0096-0039	32-021
Andrew N. Mauer (NEI)	XI.M24, "Compressed Air Monitoring," Removal of opportunistic inspections whenever components are made accessible from the AMP guidance.	ML23291A071	NRC-2023-0096-0039	32-022
Andrew N. Mauer (NEI)	XI.M27, "Fire Water System (FWS)," removal of guidance concerning FWS components that only have license renewal intended functions of leakage boundary or structural integrity, as these components are not within the scope of the FWS aging management program.	ML23291A071	NRC-2023-0096-0039	32-023
Andrew N. Mauer (NEI)	XI.M27, "FWS," revision the recommendation in Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations[a, b, c]," to perform internal inspections of sprinkler system piping as a one-time inspection.	ML23291A071	NRC-2023-0096-0039	32-024
Andrew N. Mauer (NEI)	XI.M27, "FWS," removal prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.	ML23291A071	NRC-2023-0096-0039	32-025
Andrew N. Mauer (NEI)	XI.M27, "FWS," removal of reference to flushing in Elements 3, 4, and 5, as flushing is performed as a preventive action to mitigate or prevent flow blockage and loss of material by removing foreign material and sediment.	ML23291A071	NRC-2023-0096-0039	32-026
Andrew N. Mauer (NEI)	XI.M27, "FWS," reinstate footnote (6) to Table XI.M27-1 from GALL-SLR, Revision 0, the deleted footnote related to functional testing of foam-based fire suppression systems and provided an option to perform air testing of foam sprinkler systems.	ML23291A071	NRC-2023-0096-0039	32-027
Andrew N. Mauer (NEI)	XI.M27, "FWS," revision of the recommendation to perform mainline strainer inspections to consider plant-specific configurations.	ML23291A071	NRC-2023-0096-0039	32-028
Andrew N. Mauer (NEI)	XI.M27, "FWS," elimination of recommendation to perform fire protection pump suction strainer inspections. Inspection of the fire	ML23291A071	NRC-2023-0096-0039	32-029

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
	protection pump suction strainers for vertical fire pumps annually and after system actuation is not feasible and is unnecessary.			
Andrew N. Mauer (NEI)	XI.M27, "FWS," elimination of recommendation to perform fire protection pump intake screen inspections.	ML23291A071	NRC-2023-0096-0039	32-030
Andrew N. Mauer (NEI)	XI.M27, "FWS," removal of the new footnote (f) to Table XI.M27-1, footnote (f) refers to sample flow testing of hose stations.	ML23291A071	NRC-2023-0096-0039	32-031
Andrew N. Mauer (NEI)	XI.M27, "Fire Water System," inclusion of language to acknowledge alternative methods of verifying fire water system intended functions beyond those in generic NFPA Code.	ML23291A071	NRC-2023-0096-0039	32-032
Andrew N. Mauer (NEI)	XI.M27, "FWS," clarification of the Program Description that dry sprinklers, fast response sprinklers, and standard sprinklers each have different testing or replacement frequencies in NFPA 25 (different sub-sections of the code).	ML23291A071	NRC-2023-0096-0039	32-033
Andrew N. Mauer (NEI)	Editorial comment to review and correct footnote numbering and references for Table XI.M29-1, "Tank Inspection Recommendations" affecting XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," and XI.M30, "Fuel Oil Chemistry."	ML23291A071	NRC-2023-0096-0039	32-034
Andrew N. Mauer (NEI)	XI.M32, "One-Time Inspection," Revision of Program Description and Table XI 01 to eliminate subjective guidance for inspections, for phrases "just prior" to "ten years prior."	ML23291A071	NRC-2023-0096-0039	32-035
Andrew N. Mauer (NEI)	XI.M32, "One-Time Inspection," Reduction of the number of one-time inspections, up to complete elimination of inspection recommendations, for material and environment combinations in which there is adequate operating experience indicating there is no aging concern.	ML23291A071	NRC-2023-0096-0039	32-036
Andrew N. Mauer (NEI)	XI.M32, "One-Time Inspection," Addition of heat transfer testing as an inspection method option for reduction of heat transfer due to fouling.	ML23291A071	NRC-2023-0096-0039	32-037
Andrew N. Mauer (NEI)	XI.M32, "One-Time Inspection," Addition of lubricating oil sampling for corrosion products as an inspection method for loss of material for components in lubricating oil environment.	ML23291A071	NRC-2023-0096-0039	32-038
Andrew N. Mauer (NEI)	XI.M32, "One-Time Inspection," inclusion of stainless steel as part of the steel sample population, steel is the bounding material managed by XI.M32 and, as such, if degradation is not occurring in steel, then there is reasonable assurance that no degradation is occurring in stainless steel exposed to the same service environment.	ML23291A071	NRC-2023-0096-0039	32-039

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Andrew N. Mauer (NEI)	XI.M32, "One-Time Inspection," removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.	ML23291A071	NRC-2023-0096-0039	32-040
Andrew N. Mauer (NEI)	XI.M33, "Selective Leaching," removal of opportunistic inspections whenever components are made accessible from the XI.M33 guidance.	ML23291A071	NRC-2023-0096-0039	32-041
Andrew N. Mauer (NEI)	XI.M33, "Selective Leaching," inclusion of hardness testing as an available option for performing inspections for selective leaching with acceptance criteria that remains the same as previously contained in NUREG-1801, Revision 2.	ML23291A071	NRC-2023-0096-0039	32-042
Andrew N. Mauer (NEI)	XI.M33, "Selective Leaching," rephrase Element 4 to present the information in a simple structure, similar to AMP XI.M41; breaking the contents of the element into shorter paragraphs, bullets, tables for inspection quantities by time period, and footnotes to the table.	ML23291A071	NRC-2023-0096-0039	32-043
Andrew N. Mauer (NEI)	XI.M33, "Selective Leaching," removal of the presence of green copper oxide as an acceptance criterion for detecting selective leaching of copper alloys and replace with the presence of a "white/gray meringue deposit."	ML23291A071	NRC-2023-0096-0039	32-044
Andrew N. Mauer (NEI)	XI.M33, "Selective Leaching," deletion of recommendation stating that samples are taken from multiple locations. The GALL-SLR already requires that a representative sample be inspected. The new guidance that states that samples are taken from multiple locations is unnecessary.	ML23291A071	NRC-2023-0096-0039	32-045
Andrew N. Mauer (NEI)	XI.M33, "Selective Leaching," removal of the increased sample size for buried gray cast iron components.	ML23291A071	NRC-2023-0096-0039	32-046
Andrew N. Mauer (NEI)	XI.M33, "Selective Leaching," if the NRC elects not to remove the new recommended increased sample size for buried gray cast iron, then the guidance should be revised to recommend a sample size for the entire station rather than on a per unit basis.	ML23291A071	NRC-2023-0096-0039	32-047
Andrew N. Mauer (NEI)	XI.M33, "Selective Leaching," new bullet point recommending the increased sample size for buried gray cast iron states that a technical justification for a reduced sample size can be provided and be included in the SLRA.	ML23291A071	NRC-2023-0096-0039	32-048
Andrew N. Mauer (NEI)	XI.M33, "Selective Leaching," clarification of the new bullet point recommending the increased sample size for buried gray cast iron	ML23291A071	NRC-2023-0096-0039	32-049

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
	and state that mechanical inspections of buried cast iron components are not required if the coating is intact.			
Andrew N. Mauer (NEI)	XI.M33, “Selective Leaching,” tabulation of Element 6 to be structured like the proposed mark-up of XI.M33 previously submitted to the NRC by NEI in its letter dated January 12, 2022 (ML22019A292), intended to improve readability.	ML23291A071	NRC-2023-0096-0039	32-050
Andrew N. Mauer (NEI)	XI.M33, “Selective Leaching,” removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.	ML23291A071	NRC-2023-0096-0039	32-051
Andrew N. Mauer (NEI)	XI.M33, “Selective Leaching,” if prescriptive corrective action guidance remains, sample expansion inspections for unacceptable results of inspections performed in the latter half of the 10-year inspection interval be performed within the first 4 years of the next 10-year inspection interval.	ML23291A071	NRC-2023-0096-0039	32-052
Andrew N. Mauer (NEI)	XI.M33, “Selective Leaching,” revision of Element 4 to provide for the use of Non-destructive techniques (NDT) to monitor for selective leaching.	ML23291A071	NRC-2023-0096-0039	32-053
Andrew N. Mauer (NEI)	XI.M38, “Inspection of Internal Surfaces In Miscellaneous Piping and Ducting Components,” removal of opportunistic inspections whenever components are made accessible from the XI.M38 guidance.	ML23291A071	NRC-2023-0096-0039	32-054
Andrew N. Mauer (NEI)	XI.M41, “Buried and Underground Piping and Tanks,” elimination or clarification of the coating recommendation for buried cementitious piping.	ML23291A071	NRC-2023-0096-0039	32-055
Andrew N. Mauer (NEI)	XI.M41, “Buried and Underground Piping and Tanks,” clarification of NRC recommendations with respect to cathodic protection, GALL-SLR guidance implies that cathodic protection may not be needed for certain stations or buried piping systems.	ML23291A071	NRC-2023-0096-0039	32-056
Andrew N. Mauer (NEI)	XI.M41, “Buried and Underground Piping and Tanks,” removal of reference to carbonate/bicarbonate environment, operating experience from the gas pipeline industry indicates that high-pH stress corrosion cracking can occur in a carbonate bicarbonate environment in piping directly downstream of compressor stations.	ML23291A071	NRC-2023-0096-0039	32-057
Andrew N. Mauer (NEI)	XI.M41, “Buried and Underground Piping and Tanks,” Remove HDPE guidance from XI.M41, still includes guidance related to aging	ML23291A071	NRC-2023-0096-0039	32-058

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
	effects for HDPE buried piping but this material has been removed from the AMP.			
Andrew N. Mauer (NEI)	XI.M41, “Buried and Underground Piping and Tanks,” elimination of the recommended minimum length of piping for inspections (10 linear feet).	ML23291A071	NRC-2023-0096-0039	32-059
Andrew N. Mauer (NEI)	XI.M41, “Buried and Underground Piping and Tanks,” recommendation for greater credit be given to volumetric examinations performed in lieu of external visual inspections.	ML23291A071	NRC-2023-0096-0039	32-060
Andrew N. Mauer (NEI)	XI.M41, “Buried and Underground Piping and Tanks,” provide alternative inspection options to be performed in lieu of external visual inspections for buried cementitious piping.	ML23291A071	NRC-2023-0096-0039	32-061
Andrew N. Mauer (NEI)	XI.M41, “Buried and Underground Piping and Tanks,” removal of reference to National Association of Corrosion Engineers (NACE) qualifications, as NACE no longer exists as a stand-alone organization.	ML23291A071	NRC-2023-0096-0039	32-062
Andrew N. Mauer (NEI)	XI.M41, “Buried and Underground Piping and Tanks,” recommend changing the acceptance criteria for buried piping inspections to be based on projection of wall loss through the next scheduled inspection (10 years).	ML23291A071	NRC-2023-0096-0039	32-063
Andrew N. Mauer (NEI)	XI.M41, “Buried and Underground Piping and Tanks,” removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.	ML23291A071	NRC-2023-0096-0039	32-064
Andrew N. Mauer (NEI)	XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” addition of another bullet for piping system components such as valves, pump casings, flow elements, etc., that recommends a sample-based inspection approach for these components like the sample-based approach used for piping (X% up to Y maximum number of inspections).	ML23291A071	NRC-2023-0096-0039	32-065

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Andrew N. Mauer (NEI)	XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” clarification of the definitions in lines 6-10, Note (c) Inspection Categories A and B. In SLR-ISG-2021-02-MECHANICAL Appendix H, the same note explicitly defined note (c), sub-notes 1 and 2 as Category A and B, respectively.	ML23291A071	NRC-2023-0096-0039	32-066
Andrew N. Mauer (NEI)	XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.	ML23291A071	NRC-2023-0096-0039	32-067
Andrew N. Mauer (NEI)	XI.M43, “HDPE Piping and CFRP Repaired Piping,” deletion of new GALL-SLR AMP XI.M43. The NRC's aging management guidance is based on generally applicable operating experience indicating age-related issues requiring management to ensure intended functions are maintained.	ML23291A071	NRC-2023-0096-0039	32-068
Andrew N. Mauer (NEI)	XI.M43, “HDPE Piping and CFRP Repaired Piping,” in place of GALL-SLR AMP XI.M43, aging management of HDPE and CFRP should be addressed as a TLAA.	ML23291A071	NRC-2023-0096-0039	32-069
Andrew N. Mauer (NEI)	XI.M43, “HDPE Piping and CFRP Repaired Piping,” for CFRP piping, while a TLAA approach works well for the CFRP itself, potential age-related degradation of the host pipe at the terminal ends would need to be managed.	ML23291A071	NRC-2023-0096-0039	32-070
Andrew N. Mauer (NEI)	XI.M43, “HDPE Piping and CFRP Repaired Piping,” deletion of cathodic protection recommendations for CFRP replacement piping, as cathodic protection of the terminal ends is already adequately addressed by XI.M41, “Buried and Underground Piping and Tanks.”	ML23291A071	NRC-2023-0096-0039	32-071
Andrew N. Mauer (NEI)	XI.M43, “HDPE Piping and CFRP Repaired Piping,” elimination of contradictory statements within XI.M43 and contradictions between the new XI.M43 AMP and the proposed revision to XI.M41.	ML23291A071	NRC-2023-0096-0039	32-072
Andrew N. Mauer (NEI)	XI.M43, “HDPE Piping and CFRP Repaired Piping,” revision of AMP guidance such that exceptions or plant-specific AMPs would not be required.	ML23291A071	NRC-2023-0096-0039	32-073
Andrew N. Mauer (NEI)	XI.M43, “HDPE Piping and CFRP Repaired Piping,” removal of reference to CFRP “repaired” piping. CFRP can be used to repair piping as a semi-structural repair that reinforces the original host pipe such that it meets design basis loading requirements.	ML23291A071	NRC-2023-0096-0039	32-074

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," deletion of coating inspection of the host pipe as a detection of aging effects recommendation for internally applied CFRP replacement piping.	ML23291A071	NRC-2023-0096-0039	32-075
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," deletion of reference to flow blockage/fouling. HDPE and CFRP are not susceptible to flow blockage/fouling.	ML23291A071	NRC-2023-0096-0039	32-076
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," deletion of backfill preventive action recommendation for CFRP internal replacement piping. The CFRP piping addressed by this AMP are full-structural replacements where no credit is taken for the host pipe.	ML23291A071	NRC-2023-0096-0039	32-077
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," clarification of the frequency and scope in Table XI.M43-2 (now renamed XI.M43-3) apply to the tests and inspections in Element 3, "Parameters Monitored or Inspected."	ML23291A071	NRC-2023-0096-0039	32-078
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," clarify the contradiction between Element 3, "Parameters Monitored or Inspected," and Element 4, "Detection of Aging Effects," on the terminal ends of CFRP inspections.	ML23291A071	NRC-2023-0096-0039	32-079
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," clarification of paragraph numbering for CFRP piping in Element 3, numbering appears incorrect.	ML23291A071	NRC-2023-0096-0039	32-080
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," removal of copper alloy and aluminum alloy from Table XI.M43-3, "Cathodic Protection Acceptance Criteria."	ML23291A071	NRC-2023-0096-0039	32-081
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," revision of the AMP to eliminate all testing and inspections for HDPE or CFRP piping fully backfilled in controlled low-strength material.	ML23291A071	NRC-2023-0096-0039	32-082
Andrew N. Mauer (NEI)	removal of reference to coatings in the Acceptance Criterion and Table XI.M43-2 (now renamed XI.M43-3) since HDPE piping is not coated.	ML23291A071	NRC-2023-0096-0039	32-083
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," elimination of the recommended minimum length of piping for inspections (10 linear feet).	ML23291A071	NRC-2023-0096-0039	32-084

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," deletion of Element 4 piping inspection location selection guidance that does not apply to HDPE and CFRP piping.	ML23291A071	NRC-2023-0096-0039	32-085
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," revision to state that the acceptance criterion provided in Element 6, paragraph (b)(i) only applies to the terminal ends.	ML23291A071	NRC-2023-0096-0039	32-086
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," revision to the acceptance criterion provided in Element 6, paragraph (b)(iii) to state that it only applies to the terminal ends.	ML23291A071	NRC-2023-0096-0039	32-087
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," removal of reference to NACE qualification for coating inspectors and CP4 since NACE no longer exists.	ML23291A071	NRC-2023-0096-0039	32-088
Andrew N. Mauer (NEI)	XI.M43, "HDPE Piping and CFRP Repaired Piping," removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.	ML23291A071	NRC-2023-0096-0039	32-089
Andrew N. Mauer (NEI)	Table A.4, "Spent Fuel Pool Cooling and Cleanup (BWR)," combination of GALL-SLR AMR line items III.A4.T-36 and III.A4.T-37 into one consolidated item.	ML23291A071	NRC-2023-0096-0039	32-090
Andrew N. Mauer (NEI)	XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," revision to clarify inspections and aging management of cables that are coated with fire retardant material.	ML23291A071	NRC-2023-0096-0039	32-091
Andrew N. Mauer (NEI)	XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," revision to clarify the inclusion of mechanical components associated with electrical equipment (such as gaskets, seals, O-rings, etc.), that are in the scope of this AMP.	ML23291A071	NRC-2023-0096-0039	32-092
Andrew N. Mauer (NEI)	XI.E3A, XI.E3B and XI.E3C, on "Electrical Insulation for Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," removal of requirement for level control alarm at central location or control room.	ML23291A071	NRC-2023-0096-0039	32-093
Andrew N. Mauer (NEI)	XI.E3A, XI.E3B and XI.E3C, on "Electrical Insulation for Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," deletion of the word "continuous" from the level monitoring device description, as use of this word could imply that	ML23291A071	NRC-2023-0096-0039	32-094

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
	any temporary interruption of level detection systems would negate their use in justifying less frequent inspections.			
Andrew N. Mauer (NEI)	XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," deletion of the word "potentially" in relation to exposure to moisture, wetting, or submergence of cables.	ML23291A071	NRC-2023-0096-0039	32-095
Andrew N. Mauer (NEI)	XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," deletion of the word "potentially" in relation to cable exposed to significant moisture.	ML23291A071	NRC-2023-0096-0039	32-096
Andrew N. Mauer (NEI)	XI.E3C, "Electrical Insulation For Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," deletion the word "potentially" in relation to cable exposed to significant moisture the word "potentially," and deletion of the words "multiple random," in relation to failures of the cable insulation systems; correction of "low voltage" to allow for testing on other cable types in-lieu of low-voltage power cable direct-testing if all the other listed caveats are met.	ML23291A071	NRC-2023-0096-0039	32-097
Andrew N. Mauer (NEI)	Additional AMR rows similar to VII.C1.A-409 to allow AMPs (i.e., XI.M20, XI.M27, XI.M38) to manage wall thinning due to erosion for non-FAC systems.	ML23291A071	NRC-2023-0096-0039	32-098
Andrew N. Mauer (NEI)	Reference to inspections "similar to" ASME Code Examinations VT-1 and VT-3, as to not imply that all the related requirements of the ASME Code are followed.	ML23291A071	NRC-2023-0096-0039	32-099
Andrew N. Mauer (NEI)	Simplification of GALL-SLR AMR lines to consolidate all similar air environments such as Air-Indoor Uncontrolled, Air-Outdoor, and Condensation.	ML23291A071	NRC-2023-0096-0039	32-100
Andrew N. Mauer (NEI)	Deletion of "Long-term loss of material due to general corrosion" from GALL-SLR AMR lines, associated SRP-SLR lines, and applicable AMPs; general corrosion is a slow-acting long-term aging effect that is adequately addressed through the normal "loss of material" AMR lines and is adequately managed through existing AMPs without any specific guidance.	ML23291A071	NRC-2023-0096-0039	32-101
Andrew N. Mauer (NEI)	Elimination of further evaluation SRP-SLR Sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6 addressing recurring internal corrosion.	ML23291A071	NRC-2023-0096-0039	32-102

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Andrew N. Mauer (NEI)	SRP-SLR Section 3.5.2.2.2.8, clarify the NRC's intent with respect to justification for the use of NUREG-1509 generic nil-ductility temperature values in lieu of those from plant-specific materials testing data.	ML23291A071	NRC-2023-0096-0039	32-103
Andrew N. Mauer (NEI)	SRP-SLR Section 3.5.2.2.2.8, change of the threshold value at which neutron damage could be a concern per NUREG-1509 Figure 3-1, and conservative screening for effect of embrittlement being more appropriate.	ML23291A071	NRC-2023-0096-0039	32-104
Andrew N. Mauer (NEI)	SRP-SLR Section 3.5.2.2.2.8, deletion of text correlating alloying elements with embrittlement of reactor pressure vessel support steels.	ML23291A071	NRC-2023-0096-0039	32-105
Andrew N. Mauer (NEI)	SRP-SLR Section 3.5.2.2.2.8, revision of the further evaluation section to focus only on embrittlement rather than on "combined effects of aging," other aging effects are adequately managed by existing aging management programs in GALL-SLR such that these aging effects do not need to be combined in this further evaluation.	ML23291A071	NRC-2023-0096-0039	32-106
Andrew N. Mauer (NEI)	SRP-SLR Section 3.5.2.2.2.8, revise the further evaluation to exclude skirt supported reactors.	ML23291A071	NRC-2023-0096-0039	32-107
Andrew N. Mauer (NEI)	SRP-SLR Section 4.7.4.1, "Leak-before-break Analysis," rephrase Item (v) in the final sentence of the third paragraph in Section 4.7.4.1 to say, "critical locations for LBB evaluation," as the current phrasing implies the existence of cracks in critical locations.	ML23291A071	NRC-2023-0096-0039	32-108
Andrew N. Mauer (NEI)	SRP-SLR Section 4.7.4.1, "Leak-before-break Analysis," deletion of item (ii) in final sentence of the fourth paragraph in Section 4.7.4.1, as the phrase could imply that fatigue crack growth should be performed.	ML23291A071	NRC-2023-0096-0039	32-109
Andrew N. Mauer (NEI)	SRP-SLR Section 4.7.4.2, "Pump Casing Flaw Tolerance Analysis," rephrase of text to add "crack growth" to phrases "fatigue crack growth transient cycles, and fatigue crack growth crack sizes," to improve clarity.	ML23291A071	NRC-2023-0096-0039	32-110
Andrew N. Mauer (NEI)	Table-2-29, "Chapter IX.E – Aging Effects, Differences From Chapter IX GALL-SLR Report, Revision 0, and Their Technical Base," the technical basis for the change to the Cracking definition refers to Table-2-29 for the technical basis for the new proposed XI.M43 AMP, Statement is made in Table 2-29, confirmation that this is reference should be to Table 2-33.	ML23291A071	NRC-2023-0096-0039	32-111

Table C-1 Crosswalk of Public Comment Sources, Comment IDs, and NRC ID Numbers (Continued)

Comment Submitter	Subject	ADAMS Accession Number	Regulations.gov Comment ID	NRC ID Number
Andrew N. Mauer (NEI)	Table-2-29, “Chapter IX.E – Aging Effects, Differences From Chapter IX GALL-SLR Report, Revision 0, and Their Technical Base,” the technical basis for the change to the Flow Blockage definition refers to Table-2-29 for the technical basis for the new proposed XI.M43 AMP, statement is made in Table 2-29, confirmation that this is reference should be to Table 2-33.	ML23291A071	NRC-2023-0096-0039	32-112
Andrew N. Mauer (NEI)	Table-2-29, “Chapter IX.E – Aging Effects, Differences From Chapter IX GALL-SLR Report, Revision 0, and Their Technical Base,” the technical basis for the change to the Loss of Material definition refers to Table-2-29 for the technical basis for the new proposed XI.M43 AMP, statement is made in Table 2-29, confirmation that this is reference should be to Table 2-33.	ML23291A071	NRC-2023-0096-0039	32-113
Andrew N. Mauer (NEI)	Table 2-33, “GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” The summary of significant changes column of the first change to the XI.M17, “FAC,” AMP states that the NRC is clarifying that commitments made in response to GL 89-08 were for an ongoing FAC program; while it is expected that the majority of stations made ongoing programmatic commitments in response to GL 89-08, no changes made to the GALL- SLR guidance would retroactively change the plant-specific commitments made in the responses to GL 89-08.	ML23291A071	NRC-2023-0096-0039	32-114
Andrew N. Mauer (NEI)	XI.M33, “Selective Leaching,” substantial changes to the XI.M33 guidance imposing significant burden on stations based on a single isolated event in which selective leaching was identified as a contributing cause to the failure.	ML23291A071	NRC-2023-0096-0039	32-115
Andrew N. Mauer (NEI)	XI.M43, “HDPE Piping and CFRP Repaired Piping,” no adequate technical basis is provided for the new proposed AMP XI.M43.	ML23291A071	NRC-2023-0096-0039	32-116
Nuclear Utility Group on Equipment Qualification	Comments related to preparation and maintenance of a list of in-scope equipment "mechanical" (e.g., gaskets, seals, O-rings, etc.), and aging mechanisms during license period.	ML24347A018	NRC-2023-0096-0040	33

C.3 DRAFT NUREG-2191 REVISION 1, VOLUMES 1 AND 2, NUREG-2192 REVISION 1, AND NUREG-2221 SUPPLEMENT 1, PUBLIC COMMENTS AND RESPONSES

NRC ID: 1, William Weitze - X.M1, "Fatigue Monitoring," reference updates.

Overview of Public Comment:

RG 1.207, Revision 1 was issued final in June 2018 after the publication of SRP-SLR, Revision 0 in July 2017. Therefore, the notes that say "If and when published as RG 1.207, Revision 1 Final" or similar wording should be removed in SRP-SLR, Revision 1. In addition, NUREG/CR-6909, Revision 1 was published after the publication of SRP-SLR, Revision 0. This report should be referenced as the guidance for environmentally assisted fatigue (EAF) analysis in SRP-SLR, Revision 1.

Response:

The staff agrees with the comment that RG 1.207, Revision 1 and NUREG/CR-6909, Revision 1 were published after the publication of SRP-SLR, Revision 0 and, therefore, editorial changes should be made in SRP-SLR Revision 1. The staff also agrees that these latest documents should be referenced as the guidance for EAF analysis in SRP-SLR, Revision 1.

Overview of Proposed Changes:

NUREG/CR-6909, Revision 1 provides technical bases for RG 1.207, Revision 1. Both NUREG/CR-6909, Revision 1 and RG 1.207, Revision 1 were published after the publication of SRP-SLR, Revision 0. Accordingly, the outdated footnotes that state, "If and when published as RG 1.207, Revision 1 Final" are removed in SRP-SLR, Revision 1, Sections 4.3.2 and 4.3.3. NUREG/CR-6909, Revision 1 is referenced as the latest guidance for environmentally assisted fatigue analyses in SRP-SLR, Revision 1. Consistent changes are made in GALL-SLR AMP X.M1, "Fatigue Monitoring," in GALL-SLR, Revision 1.

The following references were added to GALL-SLR AMP X.M1, "Fatigue Monitoring":

1. NRC. Regulatory Guide 1.207, "Guidelines for Evaluating the Effects of Light-Water Reactor Coolant Environments in Fatigue Analyses of Metal Components." Revision 1. ADAMS Accession No. ML16315A130. Washington, DC: U.S. Nuclear Regulatory Commission. June 2018. NRC 2018-TN8151

2. NRC. NUREG/CR-6909, "Effect of LWR Water Environments on the Fatigue Life of Reactor Materials." Revision 1. ADAMS Accession No. ML16319A004. Washington, DC: U.S. Nuclear Regulatory Commission. May 2018. NRC 2018-TN9702

3. Associated technical basis for the footnote changes are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," X.M1, "Fatigue Monitoring," and Table 3-11, "SRP-SLR, Revision 1, Chapter 4.3, Metal Fatigue, Differences from SRP-SLR, Revision 0, and Their Technical Bases."

NRC ID: 3, 11, 12, 17, Michael Gallagher; 32-036 Andrew N. Mauer (NEI) - requested that AMPs XI.M2, "Water Chemistry," XI.M30, "Fuel Oil Chemistry," XI.M32, "One-Time Inspection," and XI.M39, "Lubricating Oil Analysis," be revised to eliminate one-time inspections.

Overview of Public Comment:

The comments 3, 11, 12, and 17 requested that AMPs XI.M2 "Water Chemistry," XI.M30 "Fuel Oil Chemistry," XI.M32 "One-Time Inspection," and XI.M39 "Lubricating Oil Analysis" be revised to eliminate one-time inspections. Because there are variations between the proposed revisions to the four AMPs, the specific changes are shown individually below.

Response:

Overall the NRC staff agrees in part. The NRC staff agrees with many of the comments, disagrees with one of the comments, and is also proposing alternate changes in other cases. A generic comment applicable to the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis AMPs is provided here and then AMP-specific comments are outlined below.

The staff performed a review of the operating experience for the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis AMPs for seven subsequent license renewal applications. This review confirmed that operating experience reviews have not identified significant aging issues in systems and components covered by the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis AMPs, and on those occasions when the corrective action program has been used, it has been effective in addressing issues found during inspections and maintenance. Also, the implementation of the One-Time Inspection Program for initial renewal per NUREG-1800 will continue to provide data to verify the lack of significance of aging effects at plants as they enter their period of extended operation (i.e., year 40).

In addition, per SRP-SLR Section A.4.2, plants are required to implement programs for the ongoing review of operating experience, and plants should also periodically assess the effectiveness of aging management programs. These activities can provide objective evidence to support the conclusion that the effects of aging are managed adequately so that the intended functions of structures and components will be maintained during the subsequent period of extended operation. The staff performed a review of past subsequent license renewal applications and verified that those plants will be conducting periodic AMP and OE assessments, consistent with the NRC guidance. The plants cite the use of NEI 14-12, "Aging Management Program Effectiveness," per the guidance in NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal."

A. XI.M2 Water Chemistry

Program Description:

The water chemistry programs for boiling water reactors and pressurized water reactors are published as EPRI reports and developed, respectively, by the Boiling Water Reactor Vessel and Internals Project and Steam Generator Management Program. The guidance is widely implemented and has been in continuous use (under various names) since the 1980s. Although the NRC does not review and approve the PWR or BWR water chemistry guidelines referenced in AMP XI.M2, the NRC maintains an awareness of changes to the guidelines through periodic meetings with industry and review activities. The NRC has observed that changes to the

guidance generally reflect factors such as operating experience and best practices. The staff agrees with the changes proposed to the Water Chemistry AMP in this public comment.

B. XI.M30 Fuel Oil Chemistry

Detection of Aging Effects:

- The NRC staff agrees with the changes proposed to this portion of the Fuel Oil Chemistry AMP in this public comment because Element 4, Detection of Aging Effects, already requires inspections at least once during the 10-year period prior to the subsequent period of extended operation, and at least once every 10 years during the subsequent period of extended operation. In addition, the operating experience reviews noted above have not identified significant aging issues in systems and components covered by the Fuel Oil Chemistry AMP. Furthermore, the corrective action program has been used effectively to address issues found during inspections and maintenance covered by this AMP.
- The NRC staff has previously reviewed and accepted exceptions to multi-level sampling of tanks with frequent inventory turnover because the frequent turnover mixes the fuel oil in the tank, which negates the potential benefit of the multi-level sampling, therefore, the staff agrees with the intent of the changes proposed to this portion of the Fuel Oil Chemistry AMP in this public comment but is proposing slightly different wording.

Corrective Actions:

As noted in the public comment, the current direction under Element 7, Corrective Action, is to add a biocide when microbiologically influenced corrosion is detected. The staff agrees that the current guidance is overly prescriptive, since other options, such as replacing the fuel oil, might be more appropriate in certain situations. Therefore, the staff agrees with the intent of the changes proposed to this portion of the Fuel Oil Chemistry AMP in this public comment but is proposing slightly different wording.

C. XI.M32 One-Time Inspection

Program Description:

The Water Chemistry AMP is a mitigation program that regularly monitors the water chemistry in accordance with the Electric Power Research Institute (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 stress corrosion cracking in components exposed to a treated water environment. In the Fuel Oil Chemistry AMP, Element 4, Detection of Aging Effects, already requires inspections at least once during the 10-year period prior to the subsequent period of extended operation, and at least once every 10 years during the subsequent period of extended operation. The Lubricating Oil Analysis AMP performs periodic sampling and testing of lubricating oil for moisture and corrosion particles in accordance with equipment manufacturers recommendations or industry standards (e.g., American Society of Testing Materials [ASTM] D 6224-02). The operating experience reviews noted above have not identified significant aging issues in systems and components covered by the Water Chemistry, Fuel Oil Chemistry, or Lubricating Oil Analysis AMPs, and the corrective action program has been used effectively to address issues found during inspections and maintenance covered by these AMPs. Therefore, the staff agrees with the changes proposed to this portion of the One-Time Inspection AMP in this public comment.

Scope of Program:

The staff agrees with the intent of the changes recommended by this portion of the public comment but is proposing an alternate revision to the text. The public comment recommended eliminating a significant portion of the Scope of Program description. This description of the Scope of Program is still relevant to describe the scope for those situations where the One-Time Inspection program is still used. Instead, the NRC staff is striking the names of the three AMPs that were recommended for deletion in the public comment (i.e., Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis).

Corrective Actions:

The staff disagrees with the changes recommended by this portion of the public comment and proposes to make no changes to this portion of the GALL-SLR Report. The public comment recommended eliminating the minimum sample size of an expanded inspection and instead using the site's corrective action plan to determine the expanded inspection sample size. However, as noted on page 2-4 of Technical Bases Documents (Initial Report):

> In the Commission's Memorandum and Order of Entergy Nuclear Generation Company and Entergy Nuclear Operations, Inc. (Pilgrim Nuclear Power Station) CLI-10-14, 71 NRC 449, 465, 467 (2010), the Commission stated, "[i]n another license renewal case, we recently stated that 'reasonable assurance' is not quantified as equivalent to a 95% (or any other percent) confidence level, but is based on sound technical judgment of the particulars of a case and on compliance with our regulations," and "[n]or does any statute, regulation, or case law require the Commission to assign and apply a precise 'level or degree' of confidence to the 'reasonable assurance' standard." [Agencywide Documents Assess and Management System (ADAMS) Accession No. ML101680369].
>
> Based on the Commission's position, the staff can judge the sample size for each proposed AMP on its individual merits using sound technical judgment. The staff used the methodology for determining a sample size in Electric Power Research Institute (EPRI) Technical Report (TR) 107514, April 1998, "Age Related Degradation Inspection Method and Demonstration: In Behalf of Calvert Cliffs Nuclear Power Plant License Renewal Application," Chapter 4, "Sampling Program Description," as a basis for the maximum sample size of 25 components. This sample size provides a 90 percent confidence that 90 percent of the population does not contain an attribute. Although a quantitative confidence level is not required, the staff concluded that this level of confidence is appropriate to provide reasonable assurance versus using a higher confidence level. The staff accepted this method of establishing a representative population sample size based on the following:
>
> - The AMPs recommend the inspection of the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. A standard 90 percent confidence sample size is established based on the principle of inspecting random objects. By biasing the sample to those components most likely to experience degradation, there is a higher potential to detect an aging effect.
> - The staff concluded that for most of the components that will be inspected (e.g., piping, piping components, tanks), industry consensus standard documents were used for construction. As such, the performance of each material, environment, and aging effect should have a reasonably common potential for degradation. Therefore, inspecting 25 components should be sufficient to reveal an aging effect.

- The 20 percent sample size was established to address smaller population sizes where a sample of 25 components could result in a larger portion of the population being inspected than is necessary to establish reasonable assurance.

Consequently, the NRC staff's sound technical judgement is that the current sample size is appropriate and therefore the staff is not recommending associated changes to program element, Corrective Actions.

D. XI.M39 Lubricating Oil Analysis

Program Description:

The Lubricating Oil Analysis AMP performs periodic sampling and testing of lubricating oil for moisture and corrosion particles in accordance with equipment manufacturers recommendations or industry standards (e.g., ASTM D 6224-02). Because the operating experience reviews noted above have not identified significant aging issues in systems and components covered by the Lubricating Oil Analysis AMP, and because the corrective action program has been used effectively to address issues found during inspections and maintenance covered by this AMP, the staff agrees with the changes proposed to this portion of the Lubricating Oil Analysis AMP in this public comment.

Overview of Proposed Changes:

To eliminate mandatory one-time inspections in the XI.M2 "Water Chemistry," XI.M30 "Fuel Oil Chemistry," and XI.M39 "Lubricating Oil Analysis" AMPs, which are called out in the XI.M32 "One-Time Inspection" AMP, using risk insights gained from industry operating experience. None of these four AMPs are being eliminated and the One-Time Inspection AMP is still available for use by any other AMP when needed.

Based on the recommended changes, for several AMR items in the GALL-SLR items and SRP-SLR the One-Time Inspection AMP is removed from the AMR tables under the AMP/TLAA and column.

Associated technical basis for the changes above are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," section XI.M2, "Water Chemistry," XI.M30, "Fuel Oil Chemistry," XI.M32, "One-Time Inspection," and XI.M39, "Lubricating Oil Analysis."

NRC ID: 4, Michael Gallagher - XI.M3, "Reactor Head Closure Stud Bolting," preventative action.

Overview of Public Comment:

This comment is on the XI.M3 "Reactor Head Closure Stud Bolting" aging management program (AMP) of GALL-SLR Report, Volume 2, Revision 1. The comment proposes to modify Element 2d "Preventive Actions" that recommends upper limits for the measured yield strength (150 ksi) and the ultimate strength (170 ksi) of bolting materials for the closure studs. Specifically, the comment proposes to add the statement, *"This preventive action is not necessary if cracking is managed by volumetric examination per ASME Code, Section XI, Table IWB-2500-1, Exam Category B-G-1."*

The bases for the comment are (1) preventive action 2d, as currently written, results in many exceptions in subsequent license renewal applications; (2) preventive action 2d is an unnecessary burden that results in researching records, inventory replacements, and developing justifications for exceptions; and (3) the reactor head closure studs are monitored for cracking per ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1.

Response:

The NRC staff agrees with the comment because the volumetric examination in the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, Table IWB-2500-1, Examination Category B-G-1, specified for the reactor vessel closure studs (Item No. B6.20) is effective in monitoring and detecting degradation due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC). Preventive action 2d of the XI.M3 aging managing program in GALL-SLR that recommends upper limits on the yield and ultimate tensile strength of the stud bolting material is one of the measures to reduce the potential for SCC or IGSCC.

Overview of Proposed Changes:

In GALL-SLR Volume 2, Revision 1, XI.M3 "Reactor Head Closure Stud Bolting," Item 2, "Preventive Actions," an additional sentence is added in Element (2)(iv) that states that the preventive action is not necessary if cracking is managed by volumetric examination per ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1.

Associated technical basis for the preventive actions change is included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M3 "Reactor Head Closure Stud Bolting."

The following references were added to GALL-SLR AMP XI.M3 "Reactor Head Closure Stud Bolting:"

> American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components."

NRC-ID: 5, 32-012 Michael Gallagher - XI.M17 "Flow Accelerated Corrosion" Detection of Aging Effects Element, reassessment to ensure that adequate bases to justify exclusion from wall thickness monitoring for piping systems that are operated for less than 2 percent of plant operating time.

Overview of Public Comment:

Comment 5 (Gallagher-3) and Comment 32-012 (NEI-12) both requested that AMP XI.M17 be revised to eliminate the reassessment discussed in the "Detection of Aging Effects" program element for piping systems that had been excluded from wall thickness monitoring due to operation less than 2 percent of plant operating time. The comments note that the 2 percent exclusion is allowed by EPRI's Flow-Accelerated Corrosion guidance document, NSAC-202L, which has been revised four times since 1993. If the exclusion criterion should be reevaluated, it will be through an update of the EPRI NSAC-202L document.

Response:

The staff disagrees with Comment 5 and Comment 32-012. Component degradation is based on accumulated operation time and a yearly usage percentage criterion does not provide for operating time accumulation. As noted in the Technical Bases Document (Initial Report), regarding the addition of this guidance to XI.M17 in 2017, "Logic dictates that the 2% operating time exclusion cannot be extended for an unlimited amount of operating time." Regarding the associated guidance for the 2 percent operating time exclusion, NSAC-202L states:

> …some lines that operate less than 2% of the time have experienced damage caused by FAC [flow-accelerated corrosion]. These lines include feedwater recirculation, startup condensate lines, high pressure coolant injection, by-pass lines to the condenser, and reactor coolant inventory control. Such lines should be excluded only if no wear has been observed and confirmed operation under existing parameters is assured.

The staff notes that to meet EPRI's cautionary guidance above, some observations on the excluded piping systems would be required. It is in that context that the associated reassessment was added, with the understanding that plant operation is being extended by a factor of two from the initial designs and some reasonable efforts will be needed to assure continued operation.

Overview of Proposed Changes:

None

NRC ID: 6, 8, 10, 15, 16, 18, Michael Gallagher;32-017 Andrew N. Mauer (NEI) - eliminating prescriptive follow-up inspections from the Corrective Actions Program element from the GALL-SLR AMPs XI.M18, XI.M21A, XI.M27, XI.M29, XI.M36, XI.M38, and XI.M42 and instead allow determination by the corrective action program.

Overview of Public Comment:

The comments in total request eliminating prescriptive follow-up inspections from the Corrective Actions program element from the GALL-SLR AMPs XI.M18, XI.M21A, XI.M27, XI.M29, XI.M36, XI.M38, and XI.M42 and instead allow determination by the corrective action program.

The comments noted that in the Technical Bases Document, Initial Report, the NRC staff stated that the basis for the provision of a minimum sample size of five or 20 percent of each applicable material and environment combination was derived from Generic Letter (GL) 90-05, which addressed medium energy systems (e.g., service water) where leakage has occurred. This generic letter recommends inspecting five additional locations beyond the leaking location and the 20 percent criterion was incorporated to address limited population sizes where a minimum sample of five could result in the entire population being inspected. This criterion was stated as being consistent with several sampling-based AMPs (e.g., XI.M32, XI.M38).

The comments made the point that utilizing GL 90-05 to determine prescriptive follow-up actions is not appropriate for the following reasons:

1 GL 90-05 is addressing guidance for performing temporary non-code repairs of ASME Code Class 1, 2 and 3 Piping. There is a through wall leak while in operation, so the augmented inspections are aimed at identifying scope for the emergent, temporary repairs. The scenario is known and specific, whereas the results of a planned aging management inspection may not be.

2 The staff is applying this criterion to an aging management inspection that does not meet acceptance criteria. But the Acceptance Criteria in the effected programs could be based on a long inspection interval and not an immediate situation such as a leak on ASME Code Class 1, 2 and 3 piping. There also could be some flexibility in the acceptance criteria such as a shorter inspection interval.

3 The GL 90-05 criteria itself does not explain the technical basis. So how can the staff apply a criterion with no explained and justified technical basis?

Response:

The staff disagrees with the comments. However, the staff has added additional flexibility to the corrective action provisions.

As discussed in the Technical Bases Document (Initial Report), Table 2-29, the NRC staff has previously noted that GL 90-05 is not directly applicable to the subject AMPs; however, the expanded sample size described in GL 90-05 was nevertheless considered a reasonable approach to evaluate an extent of condition.

In Technical Bases Document (Initial Report), page 2-4, the staff noted that several sampling-based AMPs (e.g., XI.M32, XI.M38) had received recommended representative sampling sizes in the Revision 2 update to the GALL Report, but the Revision 2 update had not included a complete discussion of the basis for the staff's position, so a full discussion was added to Technical Bases Document (Initial Report). The discussion noted the following:

> In the Commission's Memorandum and Order of Entergy Nuclear Generation Company and Entergy Nuclear Operations, Inc. (Pilgrim Nuclear Power Station) CLI-10-14, 71 NRC 449, 465, 467 (2010), the Commission stated, "[i]n another license renewal case, we recently stated that 'reasonable assurance' is not quantified as equivalent to a 95% (or any other percent) confidence level, but is based on sound technical judgment of the particulars of a case and on compliance with our regulations," and "[n]or does any statute, regulation, or case law require the Commission to assign and apply a precise 'level or degree' of confidence to the 'reasonable assurance' standard." (ADAMS Accession No. ML101680369).

Based on the Commission's position, the staff can judge the sample size for each proposed AMP on its individual merits using sound technical judgment.

Technical Bases Document (Initial Report), page 2-4, further notes that for the sampling-based AMPs being discussed, the staff used the methodology from Electric Power Research Institute (EPRI) TR 107514, April 1998, "Age Related Degradation Inspection Method and Demonstration: In Behalf of Calvert Cliffs Nuclear Power Plant License Renewal Application," Chapter 4, "Sampling Program Description," as the basis for determining the maximum sample size of 25 components. This sample size provided a 90 percent confidence that 90 percent of the population did not contain an attribute. Although a quantitative confidence level was not required, the staff concluded that this level of confidence was appropriate to provide reasonable assurance versus using a higher confidence level.

For the AMPs in question in the comments 6, 8, 10, 15, 16, 18, and 32-017, within Element 7, "Corrective Actions," the licensee does use their corrective action process to determine the scope of expanded inspections, but the scope must include 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 that is inspected, whichever is less. Since the prescriptive inspections contained in the Corrective Action element are in response to an initial minimum sample size that established a 90 percent confidence that 90 percent of the population did not contain an attribute, the minimum size of the expanded scope of 5 samples or 20 percent provides reasonable assurance that the systemic or localized nature of the issue can be determined and that the appropriate corrective actions can be taken.

The NRC staff revised the scope of the expanded sample.

For the AMP in question in comment 9, AMP XI.M27 uses the 20 percent sampling size in the Detection of Aging Effects program element because it is consistent with other sampling-based programs (AMPs XI.M18, XI.M21A, XI.M29, XI.M36, XI.M38, and XI.M42) and based on the technical basis provided above. Specifically, AMP XI.27 uses the 20 percent sampling size for the recommended augmented inspections on piping segments that cannot be drained or allow water to collect and to allow for a reduced sampling size under certain conditions (Table XI.M27-1). Eliminating prescriptive follow-up inspections in the Corrective Action program element of AMP XI.M27 is addressed in the response to comments 9 and 25.

Overview of Proposed Changes:

The staff reduced the scope of the expanded sample to be as small as just two additional locations or 10 percent of the population in question and clarifying the language regarding plants with multiple units.

Specifically the staff reduced the minimum size of the expanded scope inspections from the lesser of 5 additional or 20 percent of the population, to the lesser of 2 additional or 10 percent if an initial inspection does not meet acceptance criteria.

Associated technical basis for program element, Corrective Actions, changes were added to Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Sections XI.M18, XI.M21A, XI.M27, XI.M29, XI.M36, XI.M38, and XI.M42.

Supporting Documents:

Memorandum and Order of Entergy Nuclear Generation Company and Entergy Nuclear Operations, Inc. (Pilgrim Nuclear Power Station) CLI-10-14, 71 NRC 449, 465, 467 (2010) (ADAMS Accession No. ML101680369).

NRC ID: 7, Michael Gallagher - Eliminating prescriptive corrective actions for several Aging Management Programs.

Overview of Public Comment:

The comment requests eliminating prescriptive follow-up inspections from the Corrective Actions program element from the GALL-SLR, Revision 1, AMP XI.M20, "Open-Cycle Cooling Water System" and instead allow determination by the corrective action program.

The commenter noted that in the Technical Bases Document (initial report), the staff stated that the basis for the provision of a minimum sample size of five or 20 percent of each applicable material and environment combination was derived from Generic Letter (GL) 90-05, which addressed medium energy systems (e.g., service water) where leakage has occurred. This generic letter recommends inspecting five additional locations beyond the leaking location and the 20 percent criterion was incorporated to address limited population sizes where a minimum sample of five could result in the entire population being inspected. This criterion was stated as being consistent with several sampling-based AMPs (e.g., XI.M32, XI.M38).

The commenter made the point that utilizing GL 90-05 to determine prescriptive follow-up actions is not appropriate for the following reasons:

GL 90-05 is addressing guidance for performing temporary non-code repairs of ASME Code Class 1, 2 and 3 Piping. There is a through wall leak while in operation, so the augmented inspections are aimed at identifying scope for the emergent, temporary repairs. The scenario is known and specific, whereas the results of a planned aging management inspection may not be.

The staff is applying this criterion to an aging management inspection that does not meet acceptance criteria. But the Acceptance Criteria in the effected programs could be based on a long inspection interval and not an immediate situation such as a leak on ASME Code Class 1, 2 and 3 piping. There also could be some flexibility in the acceptance criteria such as a shorter inspection interval.

The GL 90-05 criteria itself does not explain the technical basis. So how can the staff apply a criterion with no explained and justified technical basis?

Response:

The staff disagrees with the comment. As discussed in the Technical Bases Document (Initial Report), Table 2-29, the staff has previously noted that GL 90-05 is not directly applicable to the subject AMPs; however, the expanded sample size described in GL 90-05 was nevertheless considered a reasonable approach to evaluate an extent of condition.

In the Technical Bases Document (Initial Report), page 2-4, the staff noted that several sampling-based AMPs (e.g., XI.M32, XI.M38) had received recommended representative sampling sizes in the Revision 2 update to the GALL Report, but the Revision 2 update had not included a complete discussion of the basis for the staff's position, so a full discussion was added to the Technical Bases Document, Supplement 1. The discussion noted the following:

> In the Commission's Memorandum and Order of Entergy Nuclear Generation Company and Entergy Nuclear Operations, Inc. (Pilgrim Nuclear Power Station) CLI-10-14, 71 NRC 449, 465, 467 (2010), the Commission stated, "[i]n another license renewal case, we recently stated that 'reasonable assurance' is not quantified as equivalent to a 95% (or any other percent) confidence level, but is based on sound technical judgment of the particulars of a case and on compliance with our regulations," and "[n]or does any statute, regulation, or case law require the Commission to assign and apply a precise 'level or degree' of confidence to the 'reasonable assurance' standard." (Agencywide Documents Assess and Management System [ADAMS] Accession No. ML101680369)

Based on the Commissioners' position, the staff can judge the sample size for each proposed AMP on its individual merits using sound technical judgment.

The Technical Bases Document (Initial Report), page 2-4, further notes that for the sampling-based AMPs being discussed, the staff used the methodology from EPRI TR 107514, April 1998, "Age Related Degradation Inspection Method and Demonstration: In Behalf of "Calvert Cliffs Nuclear Power Plant License Renewal Application," Chapter 4, "Sampling Program Description," as the basis for determining the maximum sample size of 25 components. This sample size provided a 90 percent confidence that 90 percent of the population did not contain an attribute. Although a quantitative confidence level was not required, the staff concluded that this level of confidence was appropriate to provide reasonable assurance versus using a higher confidence level. The initial inspection scope, methods, and frequencies were established for the "Open-Cycle Cooling Water System" program in accordance with the applicant's docketed response to NRC Generic Letter 89 13. Inspection results acquired during development of the GALL-SLR, and in years since its implementation, continue to show the need for minimum expanded inspections when acceptance criteria are not met.

Overview of Proposed Changes:

Not applicable.

NRC-ID: 9, 32-025 Michael Gallagher - XI.M27, "Fire Water System," eliminating prescriptive corrective actions.

Overview of Public Comment:

Comments 9 and 32-025 requested that AMP XI.M27 be revised to remove prescriptive follow-up inspections.

Comment 9 specifically requested the following text be deleted from the third paragraph of the Corrective Actions program element: "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." In addition, the comment noted that in the Technical Bases Document (initial report), the staff stated that the basis for the provision of a minimum sample size of five or 20 percent of each applicable material and environment combination was derived from Generic Letter (GL) 90-05, which addressed medium energy systems (e.g., service water) where leakage has occurred. This generic letter recommends inspecting five additional locations beyond the leaking location and the 20 percent criterion was incorporated to address limited population sizes where a minimum sample of five could result in the entire population being inspected. This criterion was stated as being consistent with several sampling-based AMPs (e.g., XI.M32, XI.M38). The comment made the point that utilizing GL 90-05 to determine prescriptive follow-up actions is not appropriate for several reasons (see response to Comments 6, 8, 10, 15, 16, 18, and 32-017 for additional information).

Comment 32-025 stated that the guidance to remove sufficient foreign organic or inorganic material is not necessary because it is addressed through the corrective action program. The comment stated that the guidance related to performing additional tests if a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation is not necessary, due to the comprehensive nature of fire water system testing and may not be necessary due to the specific issue. The comment stated that a flush in accordance with NFPA 25 Appendix D.5 to remove loose fouling products that could block sprinklers may not be necessary due to the specific issue and that alternative cleaning methods may be more appropriate for certain sections of piping at some plants due to system design. The comment also stated that the recommendation to perform an obstruction investigation in Table XI.M27-1 should be removed because the conditions requiring an obstruction investigation are not age related and there are alternatives to address obstruction issues.

Response:

The staff partially agrees with Comment 9 and Comment 32-025.

The staff agrees that the second paragraph in the Corrective Actions program element may be removed because the third Acceptance Criteria for AMP XI.M27 in Revision 1 of NUREG-2191, Volume 2, is “no loose fouling products exist in systems that could cause flow blockage in the sprinklers or deluge nozzles.” However, to include foreign organic or inorganic material consistent with Chapter 14 of NFPA 25, the third Acceptance Criteria will be revised to state, “no loose fouling products or sufficient foreign organic or inorganic material that could cause flow blockage or obstruct pipes, sprinklers, or deluge nozzles.”

The staff disagrees with removing the third paragraph in the Corrective Actions program element for AMP XI.M27 because if a flow test or a main drain test does not meet acceptance criteria then it should be determined whether the issue is localized or widespread. However, the staff recognizes that depending on the site’s testing regime, performing additional tests may not be necessary to determine whether the issue is localized or widespread. Therefore, the staff agrees to revise the first and second sentences of the third paragraph in the Corrective Actions program element to state, “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 in locations that could be susceptible to the same obstructing material and were not in the scope of the initial tests.” Consistent with Section A.1.2.3 in Appendix A of Revision 1 of NUREG-2192, the Corrective Actions program element for AMP XI.M27 recommends determining the further extent of tests by conducting an extent of condition and extent of cause analysis, if subsequent tests do not meet acceptance criteria. Performing additional tests at other units on site with the same material, environment, and aging effect combination provides data to determine whether flow blockage is occurring at the other units.

The staff disagrees with removing the fourth paragraph in the Corrective Actions program element because it is appropriate for AMP XI.M27 to include a recommendation to evaluate the need to remove deposits to determine whether loss of material due to corrosion under deposits is occurring. However, the staff agrees that the second sentence in the fourth paragraph in the Corrective Actions program element may be deleted because Table XI.M27-1 recommends an obstruction investigation and internal inspection of piping consistent with NFPA Section 14.3. In addition, the staff agrees that the third sentence in the fourth paragraph in the Corrective Actions program element may be deleted because the Monitoring and Trending program element for AMP XI.M27 includes guidance related to confirming the timing of subsequent inspections will maintain the component’s intended function throughout the subsequent period of extended operation.

The staff disagrees with the comment related to the minimum sample size of five or 20 percent of each applicable material and environment combination. AMP XI.M27 does not use the minimum sample size of five or 20 percent in the Corrective Actions program element but uses the 20 percent sampling size in the Detection of Aging Effects program element. Specifically, AMP XI.M27 uses the 20 percent sampling size for the recommended augmented inspections on piping segments that cannot be drained or allow water to collect and to allow for a reduced sampling size under certain conditions (Table XI.M27-1). This 20 percent sampling size is used because it is consistent with other sampling-based programs (AMPs XI.M18, XI.M21A, XI.M29, XI.M36, XI.M38, and XI.M42) and based on the technical basis provided in the response to Comments 6, 8, 10, 15, 16, 18, and 32-017.

Overview of Proposed Changes:

The third Acceptance Criteria in the Acceptance Criteria program element for AMP XI.M27 is revised to include foreign organic or inorganic material consistent with Chapter 14 of NFPA 25. The first and second sentences of the third paragraph in the Corrective Actions program element for AMP XI.M27 is revised acknowledge that depending on the site's testing regime, performing additional tests may not be necessary to determine whether the issue is localized or widespread. The second sentence in the fourth paragraph in the Corrective Actions program element is deleted because Table XI.M27-1 recommends an obstruction investigation and internal inspection of piping consistent with NFPA Section 14.3. In addition, the fourth paragraph in the Corrective Actions program element is deleted because the Monitoring and Trending program element for AMP XI.M27 includes guidance related to confirming the timing of subsequent inspections will maintain the component's intended function throughout the subsequent period of extended operation.

Associated technical basis for the changes in Acceptance Criteria and Corrective Actions were added to Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M27.

NRC ID: 13, Michael Gallagher - XI.M33, "Selective Leaching," eliminating prescriptive corrective actions.

Overview of Public Comment:

The comment recommends elimination prescriptive corrective actions specified in the GALL-SLR Report, Volume 2, Revision 1, AMP XI.M33, "Selective Leaching." The minimum sample size of five or 20 percent of each applicable material and environment combination is based on GL 90-05 and is not directly applicable to the inspections of this AMP.

Response:

The NRC staff disagrees with this comment. As discussed in the Technical Bases Document (Initial Report), Table 2-29, the staff has previously noted that GL 90-05 is not directly applicable to the subject AMPs; however, the expanded sample size described in GL 90-05 was nevertheless considered a reasonable approach to evaluate an extent of condition. Based on the NRC's position as noted in the Technical Bases Document (Initial Report), page 2-4, the staff can judge the sample size for each proposed AMP on its individual merits using sound technical judgment.

As noted in GALL-SLR AMP XI.M33, Element 7 "Corrective Actions," the licensee uses their corrective action process to determine the scope of expanded inspections. But as a minimum, Element 7 requires five additional visual and mechanical inspections when visual and mechanical inspections 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 examinations did not meet the acceptance criteria. The minimum size of the expanded scope of five samples or 20 percent provides reasonable assurance that the systemic or localized in nature of the issue is determined and that the appropriate corrective actions can be taken. In addition, as noted in NUREG-2222,

"Disposition of Public Comments on the Draft Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG-2192," the basis for the reduced population size in GALL-SLR Report AMP XI.M33 (i.e., 3 percent of the population with a maximum of 10 components) credits this number of additional inspections when inspection results determine that the affected component should be replaced prior to the end of the period of extended operation.

Overview of Proposed Changes:

Not applicable.

NRC ID: 14, Michael Gallagher - XI.M35, "ASME Code Class 1 Small-Bore Piping," Table XI.M35-1, "Examinations," Note (a) to have a 10 year time period limit on the term "no history."

Overview of Public Comment:

The comment recommends modification of XI.M35, "ASME Code Class 1 Small-Bore Piping, Table XI.M35-1, "Examinations," Note (a), to put a time period limit on the term "no history," to 10 years, as this should be sufficient rather than the entire operating history.

Response:

The NRC staff does not agree with the comment. Essentially by the time Revision 1 of SLR Guidance is published, all applicants would have already completed an operating experience search relevant to this AMP during the first renewal. For SLR, an applicant and NRC staff have the benefit of the previous result and would only need to supplement the operating experience search to cover the gap as the basis for the Category selection as specified in Table XI.M35-1. The staff believes that the current wording is appropriate and adequate. This has been the case for all recent SLR reviews, applicants used the OE search from the first renewal. Therefore, there is no undue burden to the applicants. Additionally, with the current technology these searches are relatively fast and do not require a lot of resources.

Overview of Proposed Changes:

Not applicable.

NRC ID: 19, Michael Gallagher - XI.S6, "Structures Monitoring," change inspection frequency.

Overview of Public Comment:

For XI.S6, "Structures Monitoring," the comment recommends for structures that are in-scope for 10 CFR 54.4(a)(2) only, change inspection frequency from "not to exceed 5 years" to "not to exceed 10 years."

Response:

The staff disagrees with comment 19 because GALL-SLR Report, Volume 1, AMP XI.S6, Element "Detection of Aging Effects," is general guidance for structures and components and states, "The inspection frequency depends on 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." RG 1.160 states that "[i]n accordance with the rule, structural monitoring program must provide reasonable assurance that in-scope structures are capable of fulfilling their intended functions." The condition/operating experience of the structures and components described in 10 CFR 54.4(a)(2) are plant-specific. The condition/operating experience may include an aggressive environment that involves more frequent inspections based on an evaluation of the observed degradation. The 5-year inspection frequency provides a reasonable interval to ensure that aging degradation will be detected and quantified before there is loss of intended function. If structures and components described in 10 CFR 54.4(a)(2) are in scope for the purpose of aging management, their structural monitoring frequency should follow the guidance in GALL-SLR Report, Volume 1, AMP XI.S6 on an interval not to exceed 5 years.

Overview of Proposed Changes:

Not applicable.

NRC ID: 20, Michael Gallagher - Reduction of NRC staff review time for SLR applications using existing corrective action programs, operating experience program, and targeted scope and screening.

Overview of Public Comment:

The comment recommends allowance of an option for the applicant for presenting in a SLR application only changes in scope from the first LR application. The SLR applicant would incorporate scope and screening by reference to the first LRA and list SSCs identified by 10 CFR 54.37b and plant modifications since the first LR issuance.

Response:

The staff agrees with the comment. The staff notes that the SRP-SLR does not preclude an applicant from referencing the first LR application and focusing on changes for SLR. Nevertheless, the SRP-SLR is being revised to clarify the allowance of this option.

However, an effective use of this approach would be predicated on the applicant documenting the process for identifying changes and adequately describing plant modifications and other factors leading to results that differ from the first LR. Thus, the implementation of this option is being added as an issue to be discussed as part of the staff efficiencies initiative that is currently ongoing with the NRC and industry.

Overview of Proposed Changes:

SRP-SLR Section 2.1.1,"Areas of Review," is revised to note the option of focusing the scoping and screening review on changes from the first renewal application. There are no changes at this time. Staff will consider these recommendations within the SLR efficiencies initiative.

Associated technical basis for the SRP-SLR, Revision 1, Section 2.1.1, “Areas of Review,” was added to Technical Bases Document (NUREG-2221), Supplement 1, in Table 3-2.

NRC ID: 21, Michael Gallagher - Reduction of NRC staff review time for SLR applications, particularly where the applicant is proposing activities that are consistent with GALL-SLR.

Overview of Public Comment:

The comment recommends reduction in NRC staff review time for SLR applications, and in particular that if the applicant is proposing activities that are consistent with GALL-SLR, then a detailed AMP description in Appendix B is not necessary. The applicant should identify exceptions and unique plant-specific operating experience of Appendix B. Appendix A contains the Final Safety Analysis Report, Aging Management Program description, and enhancements.

The comment also recommends that the staff verify the consistency claim in the AMP audit by reviewing a sample of 20 percent of the Aging Management Programs Basis Documents. The review sample can be expanded if significant consistency issues have been identified by the staff. Significant issues are those that may have resulted in a loss of intended function if left unresolved.

Response:

The NRC staff disagrees with the comment’s specific proposed changes to SRP-SLR Revision 1 (NUREG-2192). The staff believes that the proposed change to the SRP-SLR related to Appendix B may reduce clarity in how existing site programs will be used (and enhanced) to manage the effects of aging, potentially reducing efficiency in the staff’s review. This recommended change to NUREG-2192 will not be accepted. Regarding the recommendation to review only a 20 percent sample of AMPs, the NRC is engaged in an ongoing effort to implement measures to focus review resources, including instances in which an applicant is proposing activities that are consistent with GALL-SLR (NUREG-2191). As a result, while the specific recommended change to NUREG-2192 will not be accepted, the NRC has ongoing efforts, described below, related to the review of SLR applications that will affect the time necessary for said reviews.

Specifically regarding the review of plant programs that are enhanced to be consistent with GALL-SLR, the reviewer guidance is being revised to focus on the broader objective of confirming GALL-consistency of the enhanced program, removing the explicit direction to separately document the acceptability of each enhancement. Reviewers will, however, still document their conclusions that the relevant enhanced AMP is consistent with GALL-SLR.

Next, to more broadly improve the efficiency of the license renewal review process, the NRC staff developed the License Renewal Roadmap in SECY-24-0026, “Achieving Timely Completion of License Renewal Safety and Environmental Reviews (License Renewal Roadmap)” (Agencywide Documents Access and Management System [ADAMS] Accession No. ML24059A131) and SECY-24-0026A (ML24001A364). The License Renewal Roadmap describes the staff’s goal to conduct timely and predictable initial and subsequent license renewal reviews within 18 months, while reducing resources and providing reasonable assurance of adequate protection of public health and safety.

Additionally, as part of the License Renewal Roadmap, the staff created the Tiered Approach for the safety review, which tailors the level of staff's review by incorporating risk insights, leveraging operating programs, previous reviews, NRC and industry operating experience with aging management, and takes into consideration consistency with NRC guidance documents. The Tiered Approach accomplishes the objective proposed in FRN Comment No. 21, which recommends reviewing a sample of 20 percent of the AMP basis documents in a different manner. The Tiered Approach, established in April 2024, is currently being piloted on the Dresden Nuclear Power Station, Units 2 and 3, subsequent license renewal review. The staff is revising the SRP-SLR to align with this approach, as described in the guidance changes below.

Additional information regarding the status of the Tiered Approach implementation, as well as the License Renewal Roadmap, can be found on the NRC public website: https://www.nrc.gov/reactors/operating/licensing/renewal/roadmap.html.

Finally, regarding the aspect of the comment on Appendix B of the application, the staff notes that the standard format of Appendix B is defined in NEI 17-01, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal," which is endorsed by the NRC. NEI 17-01 does not direct applicants to include a high level of AMP detail in Appendix B, and some applications have been very brief in this regard.

Overview of Proposed Changes:

In SRP-SLR Revision 1, the descriptions of the staff review procedures are revised to focus on the broader objective of verifying the GALL-consistency of the proposed AMPs, as enhanced, rather than necessarily reviewing and documenting the acceptability of each enhancement in the safety evaluation. The abstract of GALL-SLR is also revised to reflect this change. SRP-SLR Revision 1, however, still directs staff to document the overall consistency of a particular enhanced AMP with GALL-SLR. In addition, the SRP-SLR Revision 1 is revised to direct the staff to adjust the depth of its AMP reviews by considering risk insights and other factors.

The revisions are made in SLR-SLR, Revision 1, in the following sections:

- 1.2.1, "Background on the Types of Reviews"
- 3.1.2.4, "Aging Management Programs"
- 3.1.3.4, "Aging Management Programs"
- 3.2.2.4, "Aging Management Programs"
- 3.2.3.4, "Aging Management Programs"
- 3.3.2.4, "Aging Management Programs"
- 3.3.3.4, "Aging Management Programs"
- 3.4.2.4, "Aging Management Programs"
- 3.4.3.4, "Aging Management Programs"
- 3.5.2.4, "Aging Management Programs"
- 3.5.3.4, "Aging Management Programs"
- 3.6.2.4, "Aging Management Programs"
- 3.6.3.4, "Aging Management Programs"

Associated technical basis for the changes in the above SRP-SLR, Revision 1 sections were added to Technical Bases Document (NUREG-2221), Supplement 1, in Tables 3-1, 3-3, 3-4, 3-5, 3-6, 3-7, and 3-8, respectively.

NRC ID: 22, Michael Gallagher - XI.M32, "One-Time Inspection," element 4, "Detection of Aging Effects," one-time inspection should be performed after sufficient operational exposure.

Overview of Public Comment:

The comment recommends elimination of unnecessary additional detail in XI.M32, "One-Time Inspection," Element 4, "Detection of Aging Effects." Specifically, the comment recommends deletion of:

> 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.

Response:

The staff agrees in part. The wording proposed in the draft NUREG-2191, Revision 1, was too vague to provide the proper context for the proposed change. However, the proper context was noted in the Technical Bases Document, Supplement 1, which stated:

> Since the One-Time Inspection program is based on a 50 to 60-year incubation period, inspections on recently installed repairs or replacements do not provide objective evidence that adverse aging effects are not occurring at a rate that would cause a loss of intended function during the subsequent period of extended operation. This scenario occurred during the review of a carbon fiber wrap for the Indian Point LRA, when it was found that a One Time Inspection was proposed for a repair that was only in service for about 5 years. The review resulted in several management discussions and RAIs.

The staff did not eliminate any guidance but text was added to XI.M32, "One-Time Inspection," Element 4, "Detection of Aging Effects," for clarity.

Overview of Proposed Changes:

GALL-SLR (NUREG-2191)

GALL-SLR Report, Volume 2, Revision 1, XI.M32, "One-Time Inspection," Element 4, "Detection of Aging Effects," last paragraph is revised to read:

> For recently installed repairs/replacements (i.e., made within 10 years of performing the one-time inspection) that may not have sufficient operating time for aging mechanisms to be bounded by other population samples, the one-time inspection should be performed after sufficient operational exposure has occurred, (i.e., at least 10 years of operational exposure) to provide reasonable confidence in the inspection results.

NRC ID: 23, Michael Gallagher; 32-045, Andrew N. Mauer (NEI) - Samples are taken from multiple locations for various AMPs (XI.M21A, XI.M29, XI.M33, XI.M36, XI.M38, and XI.M42).

Overview of Public Comment:

The comment recommends deletion of guidance that specifies that inspection samples are taken from multiple locations for AMPs XI.M21A, "Closed Treated Water Systems," XI.M29, "Outdoor and Large Metalic Storage Tanks," XI.M33, "Selective Leaching," XI.M36, "External Surfaces Monitoring of Mechanical Components," XI.M38, "Inspection of Internal Surfaces In Miscellaneous Piping And Ducting Components," and XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks."

Response:

The staff does not agree with this comment. As documented in Technical Basis Document, Supplement 1 to NUREG 2221 (ADAMS Accession No. ML23180A208), a recent SLR applicant proposed taking all 1 foot piping samples from a single location without any technical justification for this position. The staff determined that it was necessary to clarify that 1 foot pipe samples or 1 square-foot (ft^2) sections of insulation should be taken from multiple locations to (1) ensure that the sample is representative of the entire population; and (2) alleviate the need for future questions (e.g., how performing inspections at a single location provides a sample that is representative of the entire population).

Overview of Proposed Changes:

Not applicable.

NRC ID: 24, Michael Gallagher; 32-045, Andrew N. Mauer (NEI) - XI.M43 "High-Density Polyethylene (HDPE) Piping and Carbon Fiber - Reinforced Polymer (CFRP) Repaired Piping" eliminating prescriptive corrective actions.

Overview of Public Comment:

The comment requests elimination of prescriptive follow-up inspections from the Corrective Actions program element from the GALL-SLR AMP XI.M43 and instead allowing determination of follow-on actions to address aging related degradation by the corrective action program.

The commenter noted that in the Technical Bases Document (initial report), the staff stated that the basis for the provision of a minimum sample size of five or 20 percent of each applicable material and environment combination was derived from Generic Letter (GL) 90-05, which addressed medium energy systems (e.g., service water) where leakage has occurred. This generic letter recommends inspecting five additional locations beyond the leaking location and the 20 percent criterion was incorporated to address limited population sizes where a minimum sample of five could result in the entire population being inspected. This criterion was stated as being consistent with several sampling-based AMPs (e.g., XI.M32, XI.M38).

The commenter made the point that utilizing GL 90-05 to determine prescriptive follow-up actions is not appropriate for the following reasons:

- GL 90-05 is addressing guidance for performing temporary non-code repairs of ASME Code Class 1, 2 and 3 Piping. There is a through wall leak while in operation, so the augmented inspections are aimed at identifying scope for the emergent, temporary repairs. The scenario is known and specific, whereas the results of a planned aging management inspection may not be.
- The staff is applying this criterion to an aging management inspection that does not meet acceptance criteria. But the Acceptance Criteria in the effected programs could be based on a long inspection interval and not an immediate situation such as a leak on ASME Code Class 1, 2 and 3 piping. There also could be some flexibility in the acceptance criteria such as a shorter inspection interval.
- The GL 90-05 criteria itself does not explain the technical basis. So how can the staff apply a criterion with no explained and justified technical basis?

Response:

The staff disagrees with the comment.

As discussed in the Technical Bases Document (Initial Report), Table 2-29, the staff has previously noted that GL 90-05 is not directly applicable to the subject AMPs; however, the expanded sample size described in GL 90-05 was nevertheless considered a reasonable approach to evaluate an extent of condition.

The staff disagrees with the comment that the scenario for GL 90-05 is known. The scenario for GL 90-05 is not known and is why there is the augmented inspection to determine if there are other areas with degradation. There may be further degradation or not, but it is not known until the inspection is performed. Therefore, using criteria similar to GL 90-05 is appropriate. In addition, there is flexibility in the acceptance criteria related to timing and crediting of the augmented inspection. Although GL 90-05 addresses different scenarios from the GALL-SLR and is, therefore, not directly applicable, the NRC staff considers using the expanded sample size described in GL 90-05 a reasonable approach to evaluate a condition to achieve 90 percent confidence level that the remaining population did not contain the degradation attribute. This is based on sound engineering judgement and in addition based on other sampling based programs.

In the Technical Bases Document (page 2-4), the staff noted that several sampling-based AMPs (e.g., XI.M32, XI.M38) had received recommended representative sampling sizes in the Revision 2 update to the GALL Report, but the Revision 2 update had not included a complete discussion of the basis for the staff's position, so a full discussion was added to the Technical Bases Document, Supplement 1. The discussion noted the following:

> In the Commission's Memorandum and Order of Entergy Nuclear Generation Company and Entergy Nuclear Operations, Inc. (Pilgrim Nuclear Power Station) CLI-10-14, 71 NRC 449, 465, 467 (2010), the Commission stated, "[i]n another license renewal case, we recently stated that 'reasonable assurance' is not quantified as equivalent to a 95% (or any other percent) confidence level, but is based on sound technical judgment of the particulars of a case and on compliance with our regulations," and "[n]or does any statute, regulation, or case law require the Commission to assign and apply a precise 'level or degree' of confidence to the 'reasonable assurance' standard" (ADAMS Accession No. ML101680369).

Based on the Commission's position, the staff can judge the sample size for each proposed AMP on its individual merits using sound technical judgment.

On page 2-4 in the Technical Bases Document (initial report) further notes that for the sampling-based AMPs being discussed, the staff used the methodology from EPRI TR 107514, April 1998, "Age Related Degradation Inspection Method and Demonstration: On Behalf of Calvert Cliffs Nuclear Power Plant License Renewal Application," Chapter 4, "Sampling Program Description," as the basis for determining the maximum sample size of 25 components. This sample size provided a 90 percent confidence that 90 percent of the population did not contain an attribute. Although a quantitative confidence level was not required, the staff concluded that this level of confidence was appropriate to provide reasonable assurance versus using a higher confidence level.

For the AMP in question in Comment 24, AMP XI.M43 Detection of Aging Effects program element uses one pipe segment inspection if backfill condition is in accordance with the preventive actions program element or the smaller of 1 percent of the length of pipe run or two pipe segment inspections if backfill condition is not in accordance with the preventive actions program element. In Corrective Actions program element, an expansion of sample size is conducted when the depth or extent of degradation could have resulted in a loss of pressure boundary function and when the loss of material is extrapolated to the end of the 10 year inspection interval. The number of inspections within the affected piping is doubled or increased by five, whichever is smaller. This sampling size is consistent with other sampling-based programs such as AMP XI.M41 and the technical basis provided above.

Overview of Proposed Changes:

Not applicable.

NRC ID: 25, Michael Gallagher - Deletion XI.M43, "High- Density Polyethylene (HDPE) Piping and Carbon Fiber - Reinforced Polymer (CFRP) Repaired Piping."

Overview of Public Comment:

The comment states that AMP XI.M43 should be deleted because the NRC staff has not identified a sufficient technical basis to include this aging management program in the GALL-SLR Report Revision Volume 1. The Technical Bases Document (NUREG-2221), Supplement 1 cites no technical basis as to why this program is necessary. NUREG-2191, page XI-289 cites insufficient operating experience to justify the program. It only states:

> 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 commenter indicated that there was only one OE cited with absolutely no details, so the OE could not be independently verified for applicability. The following questions were provided:

1. Where did this happen? What plant?
2. Is there a reference report? It is not cited in the references.
3. The carbon fiber wrap was “found to be degraded”. How was it degraded? Was it aging related or improper installation?
4. Was the carbon fiber wrap intended to be a permanent repair? If temporary repair, it should not require aging management.
5. M43 is also for buried piping systems. How does this single OE of an inner diameter carbon fiber wrap inform aging management on the external piping surfaces for buried conditions?
6. Is this the only OE available? Why is one OE driving an entire industry implement this program?

Response:

The staff disagrees with the comment. The new AMP was developed to manage the effects of age-related degradation mechanisms that are applicable to HDPE piping and CFRP-repaired piping. The OE exists on the failure of CFRP-repaired pipe specifically related to loss of material due to delamination that caused flow blockage at a nuclear plant. As discussed in response to comment 32-068, the staff used its engineering judgement, knowledge gained from industry experience of the aging effects of related materials, and the information provided through the proprietary OE event to determine that the aging effects and aging management appropriate for CFRP repaired and HDPE piping is most effectively addressed with a dedicated AMP.

Response to Question 1: The OE in Element 10 of AMP XI.M43 regarding the delamination in a CFRP-repaired pipe was obtained from a licensee. The licensee treated the details of the OE event as proprietary. The staff notes that CFRP and HDPE technologies have been developed by various companies. The staff determined that the technical information is proprietary consistent with the requirements in 10 CFR 2.390. The staff can only discuss non-proprietary information in AMP XI.M43 and, therefore, cannot reveal where the failure occurred and in which plant.

Response to Question 2: There is no reference report for the OE on the CFRP-repaired pipe failure. The OE was reported by the licensee for the application of CFRP and the OE information is proprietary.

Response to Question 3: It is unclear from the proprietary OE if the degradation was age-related or improper installation based on the information provided by the licensee. It would be difficult to determine from inspections if the degradation is due to aging, improper material, improper installation, or combination of them.

Response to Question 4: The CFRP is a permanent repair that restores the functionality of the pipe because the CFRP-repaired pipe that the NRC has approved has been demonstrated to support the applied loads of the host pipe.

Response to Question 5: The new XI.M43 AMP applies specifically to CFRP-repaired pipe that is internally and structurally lined by CFRP. AMP XI.M43 is not applicable to a pipe that is repaired with CFRP installed on the external surface of the pipe. The OE demonstrates that the CFRP-repaired pipe could be degraded. Therefore, an AMP is appropriate to monitor the condition of CFRP-repaired pipe. The existing XI.M41 AMP provides guidance on buried pipe other than CFRP-repaired and HDPE piping. The AMP XI.M43 only applies to CFRP repaired pipe and HDPE piping.

Externally and/or any non-structurally CFRP-repaired piping are managed by plant-specific AMPs.

Response to Question 6: As stated in the OE section of AMP XI.M43, updates will be provided as industry becomes aware of further events related to degradation of HDPE and CFRP-repaired pipe. The staff will modify Element 10 of AMP XI.M43 during a future revision if new OE is obtained and publicly available. Even if there is no OE showing degradation of CFRP-repaired pipe or HDPE pipe, it does not mean that the CFRP-repaired pipe will not be degraded due to aging in the future. The purpose of AMP XI.M43 is to monitor and manage the CFRP-repaired and HDPE piping for future degradation due to aging. This AMP assures that CFRP-repaired and HDPE piping will be appropriately monitored and managed to the end of plant license.

Overview of Proposed Changes:

Not applicable.

NRC ID: 26, Michael Gallagher - NRC technical staff use of industry Operating Experience to justify new AMP XI.M43, "HDPE Piping and CFRP Repaired Piping."

Overview of Public Comment:

The comment suggests that transparency is needed on the staff's use and evaluation of OE in relation to new AMP XI.M43, "HDPE Piping and CFRP Repaired Piping." The staff should add a detailed description of its OE review process to Technical Bases Document, Supplement 1, which provides the technical basis for NUREG-2191 and 2192. The commenter offers the following questions or comments:

- Is LIC-401, Revision 4, "NRR Reactor Operating Experience Program," (ADAMS Accession No. ML19155A036) used by the staff as a source of OE? If not, what is the staff procedure describing the OE review process? OE should be publicly available.
- The staff should list all the OE that is aging related that was screened by the LIC-401 process and determined to "Apply" for developing license renewal guidance changes in NURG-2191 and 2192. The screening decision (i.e., Level 1 or 2 of LIC-401) should be included for each OE along with ADAMS Accession number.
- If a Level 1 issue is used to incorporate changes to the guidance, it would need the staff's use justified since it is non-safety significant nor generic in nature.
- Level 2 issues are evaluated and documented in a closure memorandum. The staff should make this publicly available and summarize as technical basis in the Technical Bases Document, Supplement 1.

- If the staff used a single OE event to incorporate changes to the guidance, it would need to be very significant, and the staff's use justified.

Response:

The staff disagrees with the comment. The staff developed AMP XI.M43 to manage the effects of age-related degradation mechanisms that are applicable to HDPE and CFRP-repaired piping. OE exists on the failure of CFRP-repaired pipe specifically related to loss of material due to delamination and flow blockage at a nuclear plant. As discussed in response to comments 25 and 32-068, the staff used its engineering judgement, knowledge gained from industry experience of the aging effects of related materials, and the information provided through the proprietary OE event to determine that the aging effects and aging management appropriate for CFRP repaired and HDPE piping is most effectively addressed with a dedicated AMP.

The OE in Element 10, "Operating Experience," of AMP XI.M43 regarding the delamination in a CFRP-repaired pipe was obtained from a licensee. The licensee treated the details of the OE event as proprietary. The staff notes that CFRP and HDPE technologies have been developed by various companies. The staff has determined that the technical information is proprietary consistent with 10 CFR 2.390. Therefore, the staff can only discuss non-proprietary information in AMP XI.M43 and cannot reveal where the failure occurred and at which plant. The staff will modify Element 10 of AMP XI.M43 during a future revision if new OE is obtained and publicly available.

The staff notes that LIC-401, Revision 4, "NRR Reactor Operating Experience Program," describes a systematic process to implement the requirements of NRC Management Directive (MD) 8.7, "Reactor Operating Experience Program" (ADAMS Accession No. ML122750292). MD 8.7 sets forth the policy of the NRC for an effectively coordinated program to systematically review OE, assess its significance, provide timely and effective communication to stakeholders and apply its insights to regulatory decisions and programs affecting nuclear reactors. The staff notes that LIC-401 and MD 8.7 focus on the OE information that is available in the public domain. The NRC staff does not have a specific procedure covering proprietary OE. When considering proprietary OE, the NRC staff follows the procedures in LIC-401 to the extent possible. The OE in Element 10 of AMP XI.M43 considers both publicly available information and proprietary information. The staff has provided the publicly available information regarding CFRP degradation in Element 10 of AMP XI.M43.

For proprietary OE provided to the NRC staff, 10 CFR 2.390 of Title 10 of the *Code of Federal Regulations* (10 CFR) permits licensees to request the NRC to withhold proprietary information that was submitted from public disclosure. The NRC staff determines if the OE information may be properly withheld consistent with 10 CFR 2.390 and then considers the information for AMP XI.M43 similar to the process for publicly available information.

GALL-SLR Report, Volume 1, Appendix B, "Operating Experience for Aging Management Programs," and SRP-SLR, Volume 1, "Operating Experience for Aging Management Programs," provides an overview on how OE plays a significant role in the development and evaluation of the effectiveness of AMPs at nuclear power plants.

With regards to the significance of the OE event, the staff cannot comment on the event due to the proprietary nature of the event, but for the reasons stated in the above discussion, the staff determined that staff use of the OE was justified.

Overview of Proposed Changes:

Not applicable.

NRC ID: 29-001, Tina Taylor (EPRI) - NUREG-2191, Volume 1, Chapter II.A, Chapter Title Correction:

Overview of Public Comment:

In draft for comment NUREG-2191, Volume 1, Revision 1, Chapter II.A, page. II-5, line 1, there is a typo in chapter title which read, “PRESSURIZED WATER REACTOR CONTAMINANTS.” “CONTAMINANTS” needs to be changed to “CONTAINMENTS.”

Response:

The NRC staff, agrees, this is a typo and will be corrected.

Overview of Proposed Changes:

In NUREG-2191, Volume 1, Revision 1, Chapter II.A, page. II-5, line 1, the title, “PRESSURIZED WATER REACTOR CONTAMINANTS” is changed to “PRESSURIZED WATER REACTOR CONTAINMENTS.”

NRC ID: 29-002, 29-003, Tina Taylor (EPRI) - AMR Item IV.B2.RP-285, material stellite for insert wear surfaces, and Aging Effect/Mechanism.

Overview of Public Comment:

For the first comment (29-002) in GALL-SLR Report (NUREG-2191), Volume 1, Revision 1, Chapter IV, “Reactor Vessel, Internals, and Reactor Coolant System,” Table B2, “Reactor Vessel Internals (PWR)—Westinghouse,” Item IV.B2.RP-285 on the clevis insert assemblies, EPRI requested a minor administrative edit to specify the Stellite material description within the scope of the “Material” column entry description of the line item as “Stellite (for insert wear surface only).”

For the second comment (29-003) in GALL-SLR Report, Volume 1, Revision 1, Chapter IV, Table B2, Item IV.B2.RP-285 on the clevis insert assemblies, EPRI requested an administrative edit to delete “distortion” as a cited aging mechanism for the “Aging Effect/Mechanism” column entry of the AMR item. EPRI provided the following rationale for requesting this edit:

> It is unclear what degradation mechanism “changes in dimension due to distortion” is referring to for the clevis insert assembly components. Wear, stress relaxation, and creep are already separately listed in the “Aging Effect/Mechanism” cell. Of the degradation mechanisms applicable to reactor vessel internals, this would seem to only leave void swelling due to neutron irradiation; however, the clevis insert assembly is located so far from the core that the neutron dose will not reach a level sufficient to cause void swelling in an 80 year lifetime. The potential for void swelling and other degradation mechanisms was

considered for 80 years in the aging degradation mechanism screening evaluations of MRP-191, Revision 2. The only mechanisms screened in for the clevis insert assembly components were SCC, wear, and fatigue. Based on these considerations, it is recommended that "changes in dimension due to distortion" be deleted from this entry.

Response:

The staff agrees with comment 29-002. In the update of AMR Item IV.B2.RP-285 in SLR-ISG-2021-01-PWRVI, the staff cited the description of the material as "Stellite (for insert surfaces only)," which carried over into the version of Item IV.B2.RP-285 in Table IV.B2 of the draft NUREG-2191, Volume 1, Revision 1 (GALL-SLR, Volume 1, Revision 1) report. However, in this SLR-ISG, the staff also added Stellite as a new material for Table IX.C, "Use of Terms for Materials," (i.e., the material description table) in the GALL-SLR Report to indicate that the material may be used as a wear resistant material. So, the staff has confirmed that EPRI's comment is accurate, and the requested change can be implemented to specify the materials as "Stellite (for insert wear surfaces only)."

The staff disagrees with comment 29-003. As discussed in the draft for comment Technical Bases Document, Supplement 1, in the technical basis for the collective updates of AMR Items IV.B2.RP-285 and IV.B2.RP-399 in Table IV.B2 of NUREG-2191 (GALL-SLR), Volume 1, Revision 1, the staff included distortion as a potential aging mechanism due to reported U.S operating experience with distortion occurring in U.S. Westinghouse-design PWR clevis insert assemblies. The EPRI Materials Reliability Program (MRP) MRP-227 report versions for PWR reactor vessel internal (RVI) components include distortion as a listed aging mechanism in many of the Chapter 4 aging management tables. The staff acknowledges that Westinghouse-design clevis insert assemblies may be in lower fluence exposure zones when compared to the fluence exposure zones for designated RVI components in Westinghouse-design upper or lower internals assemblies because the clevis inserts are reactor pressure vessel (RPV) interior attachments (i.e., the clevis inserts are designated ASME Section XI, Examination Category B-N-2 reactor vessel interior attachments). Notwithstanding, at least one U.S. PWR licensee has reported distortion as occurring in one of the clevis insert assemblies in its RPV interior configuration. That is, the distortion occurred in the clevis insert assembly even though the impacted clevis insert was in a low fluence exposure zone. Based on the reported operating experience, the staff still finds it appropriate to include "distortion" as one of the applicable aging mechanisms for clevis insert assemblies in the updated version of AMR Item IV.B2.RP-285 in Table IV.B2 of NUREG-2191, Volume 1, Revision 1. However, the staff's inclusion of distortion as a listed mechanism in AMR Item IV.B2.RP-285 is not being used as a basis for altering the EPRI MRP guidance criteria for inspecting Westinghouse-design clevis insert assembly components, as set forth in MRP-227, Revision 1-A, Table 4-9, Item W14.

Overview of Proposed Changes:

The staff implemented an edit of "Material" column entry of AMR Item IV.B2.RP-285 to describe the Stellite material as "Stellite (for insert wear surfaces only)."

References:

NRC Interim Staff Guidance Document No. SLR-ISG-2021-01-PWRVI, "Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized-Water Reactors," January 2021 (ADAMS Accession No. ML20217L203). NRC 2021-TN9958

NRC ID: 29-004, Tina Taylor (EPRI) - AMR item IV.B2.RP-302 Aging Effect/Mechanism.

Overview of Public Comment:

In NUREG-2191, Volume 1, Revision 1, Chapter IV.B, Table B.2 “Reactor Vessel Internals (PWR)—Westinghouse,” page. IV-41, AMR item “IV.B2.RP-302”, the “Aging Effect/Mechanism” was erroneously listed as “Cracking due to SSC or fatigue.” “SSC” needs to be changed to “SCC” to indicate “stress corrosion cracking.”

Response:

The NRC staff, agrees, this is a typo and will be corrected.

Overview of Proposed Changes:

In NUREG-2191, Volume 1, Revision 1, Chapter IV.B, Table B.2 “Reactor Vessel Internals (PWR)—Westinghouse,” AMR item “IV.B2.RP-302,” the “Aging Effect/Mechanism” was erroneously listed as “Cracking due to SSC or fatigue.” “SSC” is changed to “SCC” to indicate “stress corrosion cracking.”

NRC ID: 29-005, Tina Taylor (EPRI) - AMR items VII.C1.AP-239, 3.3-1, 30a; VII.C1.A-739, 3.3-1, 210; and VII.G.A-648, 3.3-1, 196 revised to delete flow blockage due to fouling of HDPE piping and piping components.

Overview of Public Comment:

Comment 29-005 requested that AMR items VII.C1.AP-239, 3.3-1, 30a; VII.C1.A-739, 3.3-1, 210; and VII.G.A-648, 3.3-1, 196 be revised to delete flow blockage due to fouling of HDPE piping and piping components because one of the advantages of HDPE piping is the reduction of fouling compared to those materials HDPE often replaces.

Response:

The staff disagrees with Comment 29-005. The staff recognizes that HDPE and CFRP-repaired piping and piping components are less susceptible than metals to accumulation of particulate fouling. However, HDPE and CFRP-repaired piping and piping components exposed to raw water may experience particulate fouling due to the potential intrusion of fouling products from the raw water source. Therefore, the staff disagrees with deleting flow blockage due to fouling for AMR items VII.C1.AP-239, 3.3-1, 30a; VII.C1.A-739, 3.3-1, 210; and VII.G.A-648, 3.3-1, 196.

Overview of Proposed Changes:

Not applicable.

NRC ID: 29-006, Tina Taylor (EPRI) - deleting "loss of material due to exposure to temperature or moisture" from the list of aging effects / mechanisms in HDPE AMR line items VII.I.AP-175, VII.I.A-406, and VII.G.A-648.

Overview of Public Comment:

The comment recommends deleting "loss of material due to exposure to temperature or moisture" from the list of aging effects/mechanisms in mechanisms in HDPE AMR line items VII.I.AP-175, VII.I.A-406, and VII.G.A-648, or otherwise providing basis and reference for this in the Technical Bases Document, Supplement 1. It is not obvious how loss of material occurs due to exposure of HDPE to temperature and moisture. The technical basis for this aging effect and mechanism are not discussed in draft NUREG-2221 Supplement 1.

Response:

The staff does not agree with deleting "loss of material due to exposure to temperature or moisture" from the list of aging effects/mechanisms in HDPE AMR line items VII.I.AP-175, VII.I.A-406, and VII.G.A-648.

The staff agree with adding specific technical basis for including the loss of material due to exposure to temperature or moisture in the Technical Basis Document, Supplement 1 for the HDPE AMR line items VII.I.AP-175, VII.I.A-406, and VII.G.A-648. It is difficult to determine if the loss of material occurred because of aging, improper materials, improper fusion joint, or combination. HDPE is sensitive to high temperatures (ASME 2008-TN10987). At high temperature, HDPE will deform which could lead to the loss of material and strength. Loss of material due to degradation and/or environmental effects can occur in HDPE piping if the incorrect material is selected or an improper fusion butt joint such as electrofused joint is performed. HDPE fabrication can also introduce moisture in the resin/hydrocarbon mixture which can cause degradation in the future (ASME 2008-TN10987).

Overview of Proposed Changes:

The technical basis for including the loss of material due to exposure to temperature or moisture is added to the Technical Bases Document Supplement 1, Table 3-5, "SRP-SLR, Revision 1, Chapter 3.3, Auxiliary Systems, Differences from SRP-SLR, Revision 0, and Their Technical Bases," Table 3.3-1, Items 104, 133, 194, 196.

References:

PVP2008-61906, "Tensile Testing and Material Property Development of High Density Polyethylene Pipe Materials" https://doi.org/10.1115/PVP2008-61906, July 24, 2009. ASME 2008-TN10987

NRC ID: 29-007, Tina Taylor (EPRI) – Deletion of "moisture" from Aging Effect/Mechanism mechanisms for CFRP AMR items VII.I.AP-182, VII.I.A-420, and VII.I.A-538.

Overview of Public Comment:

Recommend Deletion of "moisture" from Aging Effect/Mechanism mechanisms for CFRP AMR items VII.I.AP-182, VII.I.A-420, and VII.I.A-538.The technical basis is not clear for why/how CFRP material is susceptible to loss of material or cracking simply due to moisture exposure. Otherwise, recommend Technical Bases Document, Supplement. 1, be revised to provide an explanation for the phenomenon.

Response:

The staff does not agree with the deletion of "moisture" from Aging Effect/Mechanism mechanisms for CFRP AMR items VII.I.AP-182, VII.I.A-420, and VII.I.A-538.

The staff does agree with adding specific technical basis for including the loss of material due to exposure to moisture in the Technical Basis Document, Supplement 1 for the XI.M43 AMP and for the HDPE AMR line items VII.I.AP-182, VII.I.A-420, and VII.I.A-538. Furthermore, although the comment did not mention loss of material due to temperature, the NRC staff is also adding a specific basis for including the loss of material due to exposure to temperature. For CFRP, exposure to environmental effects such as temperature and/or moisture can cause degradation of the epoxy resin matrix and the bond between CFRP laminate and metal substrate. Degradation of matrix will result in debonding/cracking of fiber-matrix interfacial bond, debonding/delamination/cracking of laminate layers, lowering matrix glass transition temperature, swelling of matrix, microcracking of matrix, loss watertightness, and loss of maintaining design load. Degradation of the bond between laminate and metal substrate can result in loss of material, watertightness, and maintaining design loads.

Loss of material can result from delamination of CFRP layers due to degradation of matrix from exposure to temperature and/or moisture (MIL-HDBK-17).

Overview of Proposed Changes:

The technical basis for including the loss of material due to exposure to temperature or moisture is added to the Technical Bases Document Supplement 1, Table 3-5, "SRP-SLR, Revision 1, Chapter 3.3, Auxiliary Systems, Differences from SRP-SLR, Revision 0, and Their Technical Bases," Table 3.3-1, Items 104, 133, 194, 196.

References:

MIL-HDBK-17, "Composite Materials Handbook, Volume 1. Polymer Matrix Composites Guidelines for Characterization of Structural Materials." https://indico.fnal.gov/event/13241/contributions/18146/attachments/12002/15271/MIL_Handbook_17.pdf, June 17, 2002. DOD 2002-TN10078

NRC ID: 29-008, Tina Taylor (EPRI) – recommendation to delete "that are coated with fire-retardant material" in relation to XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Overview of Public Comment:

The comment recommends deletion "that are coated with fire- retardant material" in relation to electrical insulation of cables and connectors of XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Response:

The staff agrees in part with the comment. The staff disagrees with simply deleting the phrase "that are coated with fire-retardant material" from the AMP Program Description. However, the staff agrees that the proposed wording could create confusion and unintentionally limit the scope, therefore, the staff revised the Program Description's adverse localized environment definition.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," Element 1, "Program Description," the adverse localized environment definition is revised to read, "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 and connectors, including those that are coated with fire-retardant material."

Associated technical basis for the Program Description change is included in the Technical Bases Document Supplement 1, Table 2-35, "GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

NRC ID: 29-009, Tina Taylor (EPRI) – AMP XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," Element 4, fire-retardant material.

Overview of Public Comment:

The comment recommends in XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," Element 4,"Detection of Aging Effects," delete the phrase "coated with fire-retardant material" because of changes to the adverse localized environment definition.

Response:

The staff agrees with the comment. In XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,"

Element 4, “Detection of Aging Effects,” the phrase “coated with fire-retardant material” is deleted because of clarification changes to the adverse localized environment definition.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, XI.E1, “Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” Element 4, “Detection of Aging Effects,” the phrase “coated with fire-retardant material” is deleted to read “Cables and electrical connections are inspected to identify cable and connection insulation installed in an adverse localized environment.”

Associated technical basis for the Detection of Aging Effects change is included in the Technical Bases Document Supplement 1, Table 2-35, “GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” Section XI.E1, “Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.”

NRC ID: 29-010, Tina Taylor (EPRI) - XI.E3A, “Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” recommendation to delete term “potentially” or provide guidance on what this means the Program Description.

Overview of Public Comment:

The comment recommends for XI.E3A, “Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” deletion of the term “potentially” or provide guidance on what this means the Program Description.

Response:

The staff partially agrees with the comment. The word “potentially” in the context of the areas identified by the comment is necessary to capture environmental unknowns with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring. This ensures that inaccessible cables are conservatively scoped into the AMP and adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function. Using this term in this context is consistent with EPRI aging management implementation guidance in 3002010641 (low voltage cables) and 3002000557 (medium voltage cables) as it requires a cable to be assumed as wet if it cannot be verified that it is dry in those inaccessible locations; and therefore, aging management actions are performed on those cables.

Overview of Proposed Changes:

To enhance clarity the staff will add the following text to the AMP Program Descriptions of XI.E3A, “Electrical Insulation For Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, XI.E3B, “Electrical Insulation For Inaccessible Instrument And Control Cables Not Subject to 10 CFR 50.49 Environmental

Qualification Requirements," and XI.E3C, "Electrical Insulation For Inaccessible Low Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements:"

> The word 'potentially' is necessary to capture environmental unknowns associated with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring (i.e., a cable is assumed to be wet if it cannot be verified that it is dry in inaccessible locations; and therefore, aging management actions are performed on those cables). This ensures that inaccessible cables are conservatively scoped into the AMP and adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function.

Associated technical basis for the changes in the Program Descriptions are included in the Technical Bases Document, Supplement 1, Table 2-35, "GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Sections XI.E3A, XI.E3B, and XI.E3C.

NRC ID: 29-011, Tina Taylor (EPRI) - XI.M4, "BWR Vessel ID Attachment Welds," revise reference and latest crack growth.

Overview of Public Comment:

The comment requests updating crack growth correlations referenced in XI.M4, "BWR Vessel ID Attachment Welds" to reflect Code Case N-896 instead of BWRVIP-60-A.

Response:

The NRC agrees with the comment. The crack growth correlations in Code Case N-896 represent updated data and analysis relative to the older crack growth correlations in BWRVIP-60-A. In a final rulemaking (89 FR 58039), the NRC approved Code Case N-896 without conditions. Therefore, the NRC has reviewed the technical basis of the code case as part of the rulemaking process and has no objections to the use of the updated crack growth correlations.

Overview of Proposed Changes:

In GALL-SLR Report Volume 2, Revision 1, XI.M4, "BWR Vessel ID Attachment Welds," Evaluation and Technical Basis, item 5, "5 Monitoring and Trending" the reference to "BWRVIP-60-A" is changed to "Code Case N-896."

In XI.M4, "BWR Vessel ID Attachment Welds," References, the BWRVIP-60-A reference is replaced with "ASME Code Case N-896, 'Reference Crack Growth Rate Curves for Stress Corrosion Cracking of Low Alloy Steels in Boiling Water Reactor Environments,' Section XI, Division 1. New York, New York: American Society of Mechanical Engineers, July 2023."

NRC ID: 29-012, Tina Taylor (EPRI) - XI.M7, "BWR Stress Corrosion Cracking," reference to ASME Code Case N-896.

Overview of Public Comment:

The comment recommends updating crack growth correlations referenced in XI.M7, "BWR Stress Corrosion Cracking," to reflect Code Case N-896 instead of BWRVIP-60-A.

Response:

The NRC agrees with the comment. The crack growth correlations in Code Case N-896 represent updated data and analysis relative to the older crack growth correlations in BWRVIP-60-A. In a final rulemaking (89 FR 58039), the NRC approved Code Case N-896 without conditions. Therefore, the NRC has reviewed the technical basis of the code case as part of the rulemaking process and has no objections to the use of the updated crack growth correlations.

Overview of Proposed Changes:

In GALL-SLR, Volume 2, Revision 1, XI.M7, "BWR Stress Corrosion Cracking," item 5, "Monitoring and Trending," the reference to "BWRVIP-60-A" is changed to "Code Case N-896." In addition, in the "References" section, the reference to "BWRVIP-60-A" is changed to "Code Case N-896," as follows: ASME Code Case N-896, "Reference Crack Growth Rate Curves for Stress Corrosion Cracking of Low Alloy Steels in Boiling Water Reactor Environments," Section XI, Division 1. New York, New York: American Society of Mechanical Engineers, July 2023.

Associated technical basis for the change in included in the Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," section XI.M7.

NRC ID: 29-013, 29-014, Tina Taylor (EPRI) - XI.M8, "BWR Penetrations," to revise references to refer to Code Case N-896 and latest revision of EPRI BWRVIP-190.

Overview of Public Comment:

The comment recommends updating crack growth correlations referenced in XI.M8, "BWR Penetrations," to reflect Code Case N-896 instead of BWRVIP-60-A, and revise reference to EPRI BWRVIP-190 to reflect latest revision.

Response:

The NRC agrees with both comments. The crack growth correlations in Code Case N-896 represent updated data and analysis relative to the older crack growth correlations in BWRVIP-60-A. In a final rulemaking (89 FR 58039), the NRC approved Code Case N-896 without conditions. Therefore, the NRC has reviewed the technical basis of the code case as part of the rulemaking process and has no objections to the use of the updated crack growth correlations. The reference to EPRI BWRVIP-190 is updated to reflect Revision 1.

Overview of Proposed Changes:

In GALL-SLR, Volume 2, Revision 1, XI.M8, "BWR Penetrations," Item 5, "Monitoring and Trending," reference "BWRVIP-60-A" is changed to "ASME Code Case N-896." In addition, in the "References" section, the reference to "BWRVIP-60-A" is changed to "Code Case N-896," and "BWRVIP-190" is updated to the latest revision as follows:

1. ASME Code Case N-896, "Reference Crack Growth Rate Curves for Stress Corrosion Cracking of Low Alloy Steels in Boiling Water Reactor Environments," Section XI, Division 1. New York, New York: American Society of Mechanical Engineers, July 2023.

2. BWRVIP-190, Revision 1 (EPRI 3002002623), "BWR Vessel and Internals Project, BWR Water Chemistry Guidelines," Palo Alto, California: Electric Power Research Institute. April 2014. EPRI 2014-TN8110

The associated technical basis for the change is included in the Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M8.

NRC ID: 29-015, Tina Taylor (EPRI) – Update XI.M9, "BWR Vessel Internals" reference BWRVIP 100 to Revision 1-A.

Overview of Public Comment:

The comment recommends updating the reference in XI.M9, "BWR Vessel Internals" of BWRVIP 100 to reflect Revision 1-A.

Response:

The NRC agrees with the comment. The proposed revision to GALL-SLR, XI.M9, as published in 88 FR 44160, refers to content in Revision 1-A of BWRVIP-100. Therefore, Revision 1-A is the correct reference.

Overview of Proposed Changes:

In GALL-SLR Report Volume 2, Revision1, XI.M9, "BWR Vessel Internals," under "References," the NRC replaced the reference to BWRVIP-100-A with BWRVIP-100, Revision 1-A (Electric Power Research Institute [EPRI] 3002008388), "BWR Vessel and Internals Project, Updated Assessment of the Fracture Toughness of Irradiated Stainless Steel for BWR Core Shrouds," Palo Alto, California, February 2017, ADAMS Accession No. ML17076A228.

Associated technical basis for the change in References in included in the Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M9.

NRC ID: 29-016, Tina Taylor (EPRI) – XI.M9, "BWR Vessel Internals," update reference to BWRVIP-180 to BWRVIP-180, Revision 1.

Overview of Public Comment:

The comment recommends updating XI.M9, "BWR Vessel Internals" to reflect BWRVIP-180, Revision 1, instead of BWRVIP-180.

Response:

The NRC disagrees with the comment. The BWRVIP may not submit all updated topical reports for NRC review. For example, the BWRVIP may invoke NEI 03-08, Appendix C, "Document Screening" to determine that NRC review is not necessary. As such, NRC staff does not have access to all updated proprietary BWRVIP reports. Since BWRVIP-180, Revision 1 is not docketed with the NRC, the staff cannot endorse it's use in GALL-SLR.

The NRC currently endorses BWRVIP-180 in AMP XI.M9 for inspection and flaw evaluation of access hole covers. While the NRC received a public comment suggesting that NRC endorse BWRVIP-180, Revision 1, the staff notes that the BWRVIP has not submitted BWRVIP-180, Revision 1 to NRC for review. For example, the BWRVIP may invoke NEI 03-08, Appendix C, "Document Screening" to determine that NRC review is not necessary. Since BWRVIP-180, Revision 1 is not docketed with the NRC, the staff cannot endorse it's use in GALL-SLR.

Overview of Proposed Changes:

Not applicable.

REFERENCES

BWRVIP-180, Revision 1 (EPRI 3002018312), "Access Hole Cover Inspection and Flaw Evaluation Guidelines." Palo Alto, California: Electric Power Research Institute. August 2021. EPRI 2021-TN10080

NEI-03-08, Revision 3, "Guideline for Management of Materials Issues," Washington, DC: Nuclear Energy Institute. February 2017 NEI 2017-TN9205

NRC ID: 29-017, Tina Taylor (EPRI) - XI.M9, "BWR Vessel Internals" recommendation to update BWR Water Chemistry Guidelines-2008 to Revision 1.

Overview of Public Comment:

Comment recommends in XI.M9, "BWR Vessel Internals" to update the reference to BWRVIP 190 to reflect Revision 1.

Response:

The NRC staff agrees with the comment. Consistent with the section Guidance on Use of Later Editions/Revisions of Various Industry Documents, found in Volume 1 of GALL-SLR, the staff has previously evaluated BWRVIP-190, Revision 1 for two plant-specific license renewal applications. First, when reviewing an exception documented in NUREG–2205, "Safety

Evaluation Report Related to the License Renewal of LaSalle County Station, Units 1 and 2," September 2016 (ADAMS Accession No. ML16271A039), Section 3.0.3.2.1, "Water Chemistry." The staff found that BWRVIP-190, Revision 1, "BWR Vessel and Internals Project: BWR Water Chemistry Guidelines," EPRI 3002002623, dated April 24, 2014, acceptable to cite without exception. Similarly, the staff reviewed use of BWRVIP-190, Revision 1 in the Fermi 2 license renewal application and found it to be acceptable (ADAMS Accession No. ML16190A241). During those previous reviews, the staff found that BWRVIP-190, Revision 1 "incorporates the latest industry operating experience" and that it "does not…relax any of the relevant guidelines from the previous revision."

The staff does not formally review or issue a Safety Evaluation for the various EPRI water chemistry guidelines (including BWRVIP-190, Revision 1). However, these guidelines are recognized as representing the industry's best practices in water chemistry control. Extensive experience in operating reactors has demonstrated that following EPRI chemistry guidelines minimizes the occurrence of corrosion-related failures. Further, EPRI guidelines are periodically revised to reflect evolving knowledge with respect to best practices in chemistry control. Therefore, the staff accepts the use of the latest version of the EPRI Guidelines as the basis for the water chemistry program and has updated the relevant reference to reflect the latest version.

Overview of Proposed Changes:

GALL-SLR Volume 2, Revision 1, XI.M9 BWR Vessel Internals, References, is revised to replace BWRVIP-190 with BWRVIP-190, Revision 1.

Replace BWRVIP-190 reference with:

BWRVIP-190, Revision 1 (EPRI 3002002623), "BWR Vessel and Internals Project; BWR Water Chemistry Guidelines." Palo Alto, California: Electric Power Research Institute. April 2014.

In the Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," section XI.M9, "BWR Vessel Internals," associated technical basis is added for updating the reference.

NRC ID: 29-018, Tina Taylor (EPRI) - XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel," ferrite content.

Overview of Public Comment:

The commenter requests to delete "with ferrite content ≥ 20 percent" from the sentence discussing Nonmandatory Appendix C to the 2019 ASME Code, Section XI (XI-111, line 43-44). This comment is related to GALL-SLR AMP XI.M12. The comment states that this could be interpreted as Appendix C only provides flaw evaluations for CASS materials with ferrite content ≥ 20 percent. The comment further states that the procedures in Appendix C apply to CASS with all ferrite content, including those with ferrite content ≥ 20 percent.

Response:

The staff agrees with the comment that Nonmandatory Appendix C to the 2019 ASME Code, Section XI provides flaw evaluation guidelines that cover a broad category of piping materials including for those of CASS with ferrite content ≥ 20 percent. The staff clarified the intent by editing the associated text in the AMP acceptance criteria as follows, "Nonmandatory Appendix C to the 2019 ASME Code, Section XI, includes flaw evaluation procedures for CASS."

Overview of Proposed Changes:

GALL-SLR Volume 2, Revision 1, XI.M12 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel, Acceptance Criteria, is revised accordingly to improve clarity.

In Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M12, associated technical basis is added for updating the acceptance criteria.

NRC ID: 29-019, Tina Taylor (EPRI) - XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel," correction of revision number of NUREG/CR-4513

Overview of Public Comment:

The commenter requests to change XI.M12, "Thermal Aging Embrittlement Of Cast Austenitic Stainless Steel," reference to NUREG/CR-4513, Revision 12, to Revision 2

Response:

The staff agrees with the comment the reference "NUREG/CR-4513, Revision 12," is a typo and needs to be Revision 2

Overview of Proposed Changes:

In GALL-SLR, Volume 2, Revision 2, XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel," Item 6, "Acceptance Criteria," the reference to "NUREG/CR–4513, Revision 12" is replaced with "NUREG/CR–4513, Revision 2."

In Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," section XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel," associated technical basis is added for updating the reference.

NRC ID: 29-020, 29-023, Tina Taylor (EPRI) - AMP XI.M17, "Flow-Accelerated Corrosion," reference to EPRI 3002023786 or its later revisions.

Overview of Public Comment:

The comments request that AMP XI.M17, "Flow-Accelerated Corrosion," be revised to replace the reference to EPRI 3002005530 with EPRI 3002023786. The alternate document cited in the comment is the latest version of "Recommendations for an Effective Program Against Erosive Attack."

Response:

The staff disagrees with Comments 29-020 and 29-023. The staff is not, in principle, opposed to the use of later versions of EPRI documents. However, the NRC staff cannot include a version of the EPRI document that it has not previously reviewed. As discussed in the introductory remarks in GALL-SLR, "Guidance on Use of Later Editions/Revisions of Various Industry Documents," there are two provisions associated with this, both requiring the later edition/revision to be explicitly reviewed and approved by the NRC staff. As of this writing, neither provision noted in the GALL-SLR Report has been met.

The staff notes that, as stated in the technical basis document for the current changes to the SLR guidance, the staff reviewed the earlier version of the EPRI erosion document through its efforts for the Surry subsequent license renewal application and found it could be used as the basis for a program to manage erosion mechanisms. If a future applicant chooses to follow a later version of the document, then the NRC staff's review and possible approval of the later version will be documented in its Safety Evaluation for that applicant.

Overview of Proposed Changes:

Not applicable.

NRC ID: 29-021, Tina Taylor (EPRI) - AMP XI.M17, "Flow-Accelerated Corrosion," deletion of erosion susceptibility screening, as provided in EPRI 3002005530.

Overview of Public Comment:

The comment recommends that AMP XI.M17, "Flow-Accelerated Corrosion," be revised to delete the statement about system exclusion for cavitation screening being based on 100 hours of operation per year instead of the 2 percent criterion in the EPRI erosion guidelines. The comment noted that the 100-hour criterion was based on an earlier document that did not consider the most up-to-date operating experience. In addition, the earlier document had been primarily used on Class 1 and Class 2 systems.

Response:

The staff disagrees with the comment. Although the current industry guidance for erosion mechanisms includes the 2 percent exclusion criterion, the earlier document specifying 100 hours per year (EPRI TR-112657, Revision B-A) was specifically reviewed and approved by the NRC staff (ADAMS Accession No. ML013470102) in July 1999. The staff notes that this

previous document was associated with risk-informed inservice inspection evaluations and specifically addressed cavitation erosion. In addition, during its previous license renewal reviews, the staff has identified severe cavitation situations where through-wall damage (i.e., loss of pressure boundary integrity) occurred with far fewer than 100 hours of operation per year. In that regard, the EPRI erosion guidelines acknowledge the non-linear nature of most erosion mechanisms (in contrast with the linear nature for flow-accelerated corrosion) and recommends a higher safety factor for erosion mechanism considerations.

The staff concluded that the uncertainties associated with cavitation erosion and the previous staff reviews of operating experience did not merit the introduction of conflicting guidance in license renewal documents from the previously reviewed and approved exclusion criterion of 100 hours.

Overview of Proposed Changes:

Not applicable.

NRC ID: 29-022, 32-014, Tina Taylor (EPRI) - AMP XI.M17, "Flow-Accelerated Corrosion," safety factor for erosion, removal of the minimum safety factor of 2.0 for erosion mechanisms for evaluating remaining service life of piping where erosion per EPRI 3002005530.

Overview of Public Comment:

The comment recommends that AMP XI.M17, "Flow-Accelerated Corrosion," be revised to either remove the minimum safety factor of 2.0 for erosion mechanism evaluations or to include modified safety factor language, based on information contained in a later version of EPRI's erosion program guidance.

Response:

The staff disagrees with both comments. The staff notes that the specified safety factors for evaluations of wall thickness and remaining service life specified for erosion mechanisms comes directly from industry guidance documents that have been reviewed and approved by the NRC staff. The staff recognizes that industry guidance documents are routinely updated to account for more recent operating experience or further research. However, as discussed in the introductory remarks in the GALL-SLR Report, "Guidance on Use of Later Editions/Revisions of Various Industry Documents," there are two provisions associated with this, both requiring the later edition/revision to be explicitly reviewed and approved by the NRC staff. As of this writing, neither of the provisions noted in the GALL-SLR Report have been met for the later version of EPRI's erosion program guidance.

As noted in the technical basis document for the current changes to the SLR guidance, the staff reviewed the earlier version of the EPRI erosion document through its efforts for the Surry subsequent license renewal application and found it could be used as the basis for a program to manage erosion mechanisms. If a future applicant chooses to follow a later version of the document, then the NRC staff's review and possible approval of the later version will be documented in its Safety Evaluation for that applicant.

Overview of Proposed Changes:

Not applicable.

NRC ID: 29-024, Tina Taylor (EPRI), 32-053 (NEI), - XI.M33, "Selective Leaching," use of non-destructive examination techniques.

Overview of Public Comment:

AMP XI.M33 should be revised to include non-destructive examination (NDE) techniques.

Response:

The staff does not agree with this comment based on its observations (shown below) documented in its audit report related to the NEI proposed revision to GALL-SLR Report AMP XI.M33, "Selective Leaching" (ADAMS Accession No. ML22353A608). Applicants have the option to propose using a specific NDE technique in lieu of destructive examinations by taking an exception to the AMP and providing a technical justification for the staff to evaluate.

> "The proposed AMP revision introduces "[n]ondestructive examination techniques demonstrated to be capable of detecting the presence and/or extent of selective leaching on the component" as an inspection method. The staff notes NDE for selective leaching has not achieved widespread acceptance. In addition, EPRI Reports 3002020832, "Electromagnetic NDE Techniques for Detection of Selective Leaching in Gray Cast Iron Piping," and 3002020830, "Ultrasonic NDE Techniques for Detection of Selective Leaching in Complex Shaped Gray Cast Iron Components," note this effort is an ongoing research project (i.e., not a proven practice) and is applicable to gray cast iron (i.e., only one of the four materials within the scope of GALL-SLR Report AMP XI.M33). Furthermore, the staff reviewed EPRI Report 3002020832 and noted nondestructive examination techniques can be non-conservative (i.e., estimates greater remaining wall thickness) when compared to pit gauges and laser profilometry. The staff notes that footnote (3) of the proposed revisions to GALL-SLR Report Table XI.M33-1 equates volumetric NDE (capable of detecting selective leaching) with a destructive examination. It is not clear that NDE that is only capable of detecting selective leaching can also be used to evaluate fitness-for-service comparable to a destructive examination. Based on the reasons provided above, the technical basis for introducing NDE techniques in the proposed AMP revision should be provided."

Overview of Proposed Changes:

Not applicable.

NRC ID: 29-025, Tina Taylor (EPRI); 32-044 (NEI), - XI.M33, "Selective Leaching," elements 4 and 6, visual indicators of selective leaching.

Overview of Public Comment:

Comment recommends (1) adding "white/grey meringue deposit" to the list of visual indicators of selective leaching for copper alloys; and (2) removing the presence of green copper oxide as an acceptance criterion for detecting selective leaching of copper alloys.

Response:

The staff agrees with adding "white/grey meringue deposit" to the list of visual indicators of selective leaching for copper alloys based on its review of EPRI Report 3002020822, "Accelerated Testing and Evaluation of Factors Affecting Selective Leaching Susceptibility," and Corrosion of Copper and its Alloys - A Practical Guide for Engineers during its audit of the NEI proposed revision to GALL-SLR Report AMP XI.M33 (ADAMS Accession No. ML22353A608).

The staff does not agree with removing the presence of green copper oxide as an acceptance criterion for detecting selective leaching of copper alloys. As noted in the technical bases for changes in the subsequent license renewal guidance documents (initial report), green copper oxide was added based on staff field observations of dealloying in aluminum bronze components.

Overview of Proposed Changes:

Accordingly, the staff made revisions in two places: (a) GALL-SLR Volume 2, Revision 1, AMP XI.M33, "Selective Leaching," "detection of aging effect" program element to add the "white/grey meringue deposit" visual indicator; and (b) the Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," to add the appropriate technical basis for the change.

The following references were added to GALL-SLR AMP XI.M33, "Selective Leaching:"

1. Francis, R. (2010). Corrosion of Copper and its Alloys - A Practical Guide for Engineers. NACE International. Francis 2009-TN10166

2. Electric Power Research Institute. EPRI 3002020822, "Accelerated Testing and Evaluation of Factors Affecting Selective Leaching Susceptibility." September 15, 2021. EPRI 2021-TN10167

NRC ID: 29-026, Tina Taylor (EPRI)- XI.M33, "Selective Leaching," addition of EPRI report references.

Overview of Public Comment:

The comment recommends including five EPRI reports as references for the selective leaching aging management program.

Response:

The staff agrees with this comment in part. Four out of five of the references will be added because they were reviewed by the staff during its audit related to the NEI proposed revision to GALL-SLR Report AMP XI.M33, “Selective Leaching” (ADAMS Accession No. ML22353A608). However, EPRI Report 3002023785, “Evaluation of Electromagnetic NDE Techniques for Detection of Wall Thinning Due to Selective Leaching Degradation in Gray Cast Iron Piping,” was published in April 2023 and has not been reviewed by the staff. Therefore, this document will not be added as a reference to GALL-SLR Report AMP XI.M33.

Overview of Proposed Changes:

Revise the “references” section of GALL-SLR Volume 2, Revision 1, AMP XI.M33, “Selective Leaching,” to add the EPRI references, excluding the EPRI Report 3002023785, for the reasons stated above.

The following references were added to GALL-SLR AMP XI.M33, “Selective Leaching:”

EPRI. EPRI 3002020832, “Electromagnetic NDE Techniques for Detection of Selective Leaching in Gray Cast Iron Piping.” Palo Alto, California: Electric Power Research Institute. September 15, 2021. EPRI 2021-TN10168

EPRI. EPRI 3002020830, “Ultrasonic NDE Techniques for Detection of Selective Leaching in Complex Shaped Gray Cast Iron Components.” Palo Alto, California: Electric Power Research Institute. July 2, 2021. EPRI 2021-TN10169

EPRI. EPRI 3002020822, “Accelerated Testing and Evaluation of Factors Affecting Selective Leaching Susceptibility.” Palo Alto, California: Electric Power Research Institute. September 15, 2021. EPRI 2021-TN10167

EPRI. EPRI 3002016057, “Selective Leaching: State-of-the-Art Technical Update.” Palo Alto, California: Electric Power Research Institute. December 20, 2019. EPRI 2019-TN10170

NRC ID: 29-027, Tina Taylor (EPRI); 32-060 NEI, - XI.M41, “Buried and Underground Piping and Tanks,” element 4, in-scope piping.

Overview of Public Comment:

The comment recommended deleting the 25 percent inspection sample size for internal volumetric examinations of piping in AMP XI.M41. The comment further states that internal volumetric exams should be treated equivalent to any external visual exams with regard to length of inspection requirements.

Response:

The staff agrees with this comment in part. The staff agrees that inspecting 25 percent of the piping is not consistent with the staff’s sampling approach in other GALL-SLR Report programs (i.e., in addition to citing percentages, the extent of inspections are typically capped at a specific number of components to prevent oversampling). However, based on engineering judgment, the

staff does not agree that a reduction to the minimum number of inspections in GALL-SLR Report Table XI.M41-2, "Inspection of Buried and Underground Piping and Tanks," (i.e., the smaller of 0.5 percent of the piping length or 10 feet) provides a reasonable sample in all instances. However, based on engineering judgement, the staff has determined that the maximum number of inspections in GALL-SLR Report Table XI.M41-2 (i.e., the smaller of 10 percent of the piping length or 60 feet) would provide a reasonable sample instead of 25 percent. Applicants have the option of proposing a further reduction by taking an exception to the AMP and providing a technical justification for the staff to evaluate.

Overview of Proposed Changes:

Based on the comments, the staff made revisions in two places: (1) GALL-SLR Report, Volume 2, Revision 1, AMP XI.M41; and (2) a new Technical Bases Document, Supplement 1, input for this change.

Revise GALL-SLR Report, Volume 2, Revision 1, AMP XI.M41, "Buried and Underground Piping and Tanks," Element 4 (e)(iii), to read as follows:

> iii. The smaller of 10 percent or 60 feet of the in-scope piping constructed from the material under consideration is internally inspected by a method capable of precisely determining pipe wall thickness.

Associated technical basis for the Detection of Aging Effects program element changes are included in the Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M41.

NRC ID: 29-028, Tina Taylor (EPRI); 32-061, NEI - XI.M41, "Buried and Underground Piping and Tanks," element 4, inclusion of alternative inspection approaches for cementitious piping.

Overview of Public Comment:

The comment recommends providing alternative inspection options (in lieu of external visual inspections) for buried or underground cementitious piping in AMP XI.M41, such as electromagnetic techniques to detect wire breaks.

Response:

The NRC staff disagrees with the comment. Although the inspection techniques referenced in the comments may be suitable alternatives to performing external visual inspections of buried or underground cementitious piping, the staff does not agree that revisions to GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," are warranted based on the reasons provided in the bullets below. Applicants have the option to propose an alternative inspection technique (in lieu of performing external visual inspections) by taking an exception to the AMP and providing a technical justification for the staff to evaluate.

- The staff reviewed two recent license renewal applications and six recent subsequent license renewal applications and identified only one application where a site had cementitious piping within the scope of the Buried and Underground Piping and Tanks

program. In the instance where a site had cementitious piping within the scope of this program, the applicant proposed performing an inspection of a surrogate concrete structure in lieu of external visual inspections of the piping, which the staff approved (ML20052F523). The staff has determined that adding alternative inspection techniques is not warranted based on the limited number of sites that have in-scope cementitious piping exposed to buried or underground environments and the possibility of applicants taking an exception to the AMP.

- The public comments reference electromagnetic techniques to detect wire breaks. While the staff supports the use of these inspections to detect embedded defects in piping, the focus of GALL-SLR Report AMP XI.M41 is managing the aging of the external surfaces of buried and underground piping and tanks.
- The EPRI Reports referenced in the public comment are not readily accessible to the staff for review (i.e., based on a review of the EPRI public website on 12/13/2023, these documents can only be downloaded at a significant cost). Therefore, the staff could not use the information in these reports to create a basis for why these alternative inspection options for cementitious piping should be included in GALL-SLR Report AMP XI.M41.

Overview of Proposed Changes:

Not applicable.

NRC ID: 29-029, Tina Taylor (EPRI) - XI.M41, "Buried and Underground Piping and Tanks," reference to EPRI report 3002018352.

Overview of Public Comment:

The comment recommends replacing reference to EPRI report 1021175 with: EPRI report 3002018352, "Recommendations for an Effective Program to Control the Degradation of Buried and Underground Piping and Tanks," (1016456, Revision 2).

Response:

The staff agrees with this comment. Proposed change is incorporated by revising the "references" section of GALL-SLR Report, Volume 2, Version 1, AMP XI.M41, "Buried and Underground Piping and Tanks," to update the subject EPRI reference to the next revision.

Overview of Proposed Changes:

The NRC staff updated the "references" section of GALL-SLR Report, Volume 2, Version 1, AMP XI.M41, "Buried and Underground Piping and Tanks," as follows:

EPRI. EPRI 3002018352, "Recommendations for an Effective Program to Control the Degradation of Buried and Underground Piping and Tanks," (1016456, Revision 2). Palo Alto, California: Electric Power Research Institute, November 2020. EPRI 2020-TN10982

NRC ID: 29-030, Tina Taylor (EPRI) - XI.M43, "High-Density Polyethylene (HDPE) Piping and Carbon Fiber-Reinforced Polymer (CFRP) Repaired Piping," recommendation to clarify which AMP should be credited with managing effects of aging for buried non-safety related HDPE and aboveground HDPE piping.

Overview of Public Comment:

The comment recommends clarifying which AMP should be credited with managing any effects of aging for buried non-safety-related HDPE, as well as for aboveground HDPE piping. Neither AMP XI.M41, "Buried and Underground Piping and Tanks," nor XI.M43, "High-Density Polyethylene (HDPE) Piping and Carbon Fiber-Reinforced Polymer (CFRP) Repaired Piping," appear to address these pipes. The statements in XI.M43, Element 1, "1. Scope of Program," and Element 3, "Parameters Monitored or Inspected," paragraph (a)(i), imply that the XI.M43 only applies to safety-related HDPE piping. AMP XI.M41 Program Description (page XI-255, lines 17-20) states that HDPE pipe is not managed by XI.M41.

Response:

The staff agrees with the public comment. To ensure the applicability of AMP XI.M43 is clearly specified, the staff revised, in part, XI.M43 "Program Description," "Scope of the Program," and "Parameters Monitored or Inspected," paragraph 3(a)(i).

XI.M43 is revised to clarify its applicability to buried, underground, safety-related, and in-scope non-safety-related HDPE piping and CFRP-repaired piping.

The staff did not develop AMP XI.M43 to be applicable to any aboveground HDPE and CFRP-repaired piping because the licensees have not submitted any alternative requests and the NRC has not authorized any alternative requests for their use in nuclear plants. For any potential above ground non-safety-related HDPE piping or CFRP-repaired piping that may come in the scope of licensee renewal, a plant-specific aging management should be used.

Overview of Proposed Changes:

For clarity,

- The staff added the phrase "buried, underground, safety-related, and in-scope non-safety-related" to XI.M43, "Program Description," and "Scope of Program."
- The staff added the phrase, "When HDPE is referenced for non-safety-related piping that is in the scope of this AMP, the HDPE should continue to meet the original construction or fabrication code.
- The staff added the phrase "Visual inspections of the external and internal surface condition of the in-scope non-safety-related HDPE piping are conducted per the requirements of construction code, or plant procedures." to XI.M43, "Parameters Monitored or Inspected," paragraph 3(a)(i)

  Associated technical basis for the Program Description, Scope of Program, and Parameters Monitored or Inspected changes are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M43.

NRC ID: 29-031, Tina Taylor (EPRI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," recommendation to delete "loss of material due to radiation, temperature, and moisture," on material aging effect/mechanism.

Overview of Public Comment:

The commenter recommends editing XI.M43, "HDPE Piping and CFRP Repaired Piping," to delete "loss of material due to radiation, temperature, and moisture." It is not obvious or clear how loss of material occurs due to HDPE and CFRP exposure to environmental elements like temperature, moisture, and radiation. The basis and references for aging effect / mechanism are not addressed in draft revision of the Technical Bases Document, Supplement 1.

Response:

Response to Public Comment on Radiation: The staff agrees and deleted "radiation" from AMP XI.M43.

Response to Public Comment on Temperature and Moisture: The staff disagrees with portion of the comment asking the staff to delete loss of material due to temperature and moisture. The staff agrees with adding specific technical basis for including the loss of material due to exposure to temperature or moisture in the Technical Basis Document, Supplement 1 for the XI.M43 AMP and for relevant HDPE AMR line items. For CFRP, the staff notes that exposure to environmental effects such as temperature and/or moisture can cause degradation of epoxy resin matrix in CFRP composite and degradation of bond between laminate and metal substrate. Degradation of matrix can result in debonding/cracking of fiber-matrix interfacial bond, debonding/delamination/cracking of laminate layers, lowering matrix glass transition temperature, swelling of matrix, microcracking of matrix, loss of watertightness, and loss of maintaining design load. Degradation of bond between laminate and metal substrate can result in loss of watertightness and loss of maintaining design loads. Therefore, loss of material can result from delamination of layers due to degradation of matrix from exposure to temperature and/or moisture [MIL-HDBK-17].

For HDPE, loss of material due to degradation caused by environmental effects such as temperature and/or moisture can occur, particularly if the incorrect material is selected or an improper fusion butt joint such as electrofused joint is performed. However, it is difficult to determine if the environmental degradation is caused by improper installation, aging, or a combination of both. HDPE is sensitive to high temperatures [ASME 2008-TN10987]. At high temperatures HDPE will deform which could lead to the loss of material and strength. HDPE fabrication can introduce moisture in the resin/hydrocarbon mixture which can cause degradation in the future.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, the staff deleted "radiation" from AMP XI.M43, Element 3, "Parameters Monitored or Inspected," paragraphs (a)(i)(1) and (b)(i)(1).

Associated technical basis for the Parameters Monitored or Inspected changes are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," section XI.M43.Associated technical basis for the loss of material due to exposure to moisture and temperature, in the

Parameters Monitored or Inspected AMP element, is included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M43. Also technical bases are added to Table 3-5, "SRP-SLR, Revision 1, Chapter 3.3, Auxiliary Systems, Differences from SRP-SLR, Revision 0, and Their Technical Bases," Table 3.3-1, Items 104, 133, 194, 196.

References:

MIL-HDBK-17, "Composite Materials Handbook, Volume 1. Polymer Matrix Composites Guidelines for Characterization of Structural Materials." https://indico.fnal.gov/event/13241/contributions/18146/attachments/12002/15271/MIL_Handbook_17.pdf, June 17, 2002 DOD 2002-TN10078

PVP2008-61906, "Tensile Testing and Material Property Development of High Density Polyethylene Pipe Materials" https://doi.org/10.1115/PVP2008-61906, July 24, 2009. ASME 2008-TN10987

PVP2008-61906, "Tensile Testing and Material Property Development of High Density Polyethylene Pipe Materials" https://doi.org/10.1115/PVP2008-61906, July 24, 2009. ASME 2008-TN10987

NRC ID: 29-032, Tina Taylor (EPRI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," technical basis for HDPE and CFRP materials accumulating particulates.

Overview of Public Comment:

The comment recommends deleting "accumulation of particulate fouling (raw water systems)." The technical basis for HDPE and CFRP materials accumulating particulates is not clear. In fact, these materials are more resistant to fouling than the metallic materials they typically replace. It is also not clear how they "accumulate" particulate. Recommend deletion of "flow blockage" from AMP XI.M43, Element 1, "Scope of Program," or otherwise provide technical basis and examples in the Technical Bases Document, Supplement 1.

Response:

The staff disagrees with the comment. The staff recognizes that HDPE and CFRP-repaired pipes may be less susceptible than metals to fouling. However, uncertainty exists about whether CFRP-repaired pipe or HDPE pipe will not have fouling problems after many years of transporting raw water from an untreated water source. Therefore, the staff established AMP XI.M43 to monitor the CFRP-repaired pipe and HDPE pipe for fouling.

Overview of Proposed Changes:

Not applicable.

NRC ID: 29-033, Tina Taylor (EPRI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," recommendation that the program scope address external applications of CFRP.

Overview of Public Comment:

The commenter recommends that the XI.M43 program scope also address external applications of CFRP, not just internal applications. EPRI has observed industry applications of CFRP to the external surfaces of non-safety-related piping, such as condensate system piping. The new AMP XI.M43 should more completely address:

- HDPE for both safety-related and non-safety-related systems.
- Internal CFRP applications for both safety-related and non-safety-related systems.
- External CFRP applications for both safety-related and non-safety-related systems.

Response:

The staff disagrees with the public comment. The staff has approved the use of CFRP on the internal surface of Class 3 buried and underground piping as structural lining at nuclear plants. The staff has not received any requests from licensees for the application of CFRP on the external surface of pipes. Therefore, the staff determines that the external surface application of the CFRP is not required to be included in this AMP at this time.

AMP XI.M43 addresses the safety-related and in-scope non-safety related buried and underground metal pipe that has CFRP installed on the interior surface as structural lining.

AMP XI.M43 is applicable to buried and underground HDPE piping that is used for both safety-related and in-scope non-safety-related piping systems.

Overview of Proposed Changes:

Not applicable.

NRC ID: 29-034, Tina Taylor (EPRI) - SRP-SLR, Section 3.1.2.2.14, "Loss of Preload Due to Thermal or Irradiation- Enhanced Stress Relaxation," incorporation by reference of BWRVIP- 25, Revision 1-A.

Overview of Public Comment:

The commenter recommends revising SRP-SLR Section 3.1.2.2.14 "Loss of Preload Due to Thermal or Irradiation-Enhanced Stress Relaxation" to reflect BWRVIP-25, Revision 1-A, which provides an NRC-approved methodology to justify elimination of core plate hold-down bolt inspections.

Response:

The NRC staff agrees with this comment because updating SRP-SLR Section 3.1.2.2.14 addresses the availability of BWRVIP 25, Revision 1-A that was issued in September 2020, which was after the issuance of SRP-SLR in 2017. The NRC staff noted that updates to the corresponding "review procedures" in SRP-SLR Section 3.1.3.2.14 are also necessary.

Overview of Proposed Changes:

SRP-SLR Sections 3.1.2.2.14, “Loss of Preload Due to Thermal or Irradiation-Enhanced Stress Relaxation,” and 3.1.3.2.14, “Loss of Preload Due to Thermal or Irradiation-Enhanced Stress Relaxation” are updated to reflect the issuance of BWRVIP-25, Revision 1-A, which provides an NRC-approved methodology to justify elimination of core plate hold-down bolt inspections.

References:

EPRI. EPRI TR–3002018310, “BWRVIP-25, Revision 1-A, BWR Vessels and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines.” Palo Alto, California: Electric Power Research Institute. September 2020 (EPRI 2020-TN9699).

NRC ID: 30-001, Analysis and Measurement Services Corporation (AMS)- XI.E1, “Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” clarification of the definition of adverse localized environment.

Overview of Public Comment:

The comment seeks clarification of the definition of adverse localized environment in XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.”

Response:

The staff agrees with the comment because the existing definition could cause confusion and unintentionally limit the scope of this AMP with respect to electrical insulation for electrical cables and connectors; therefore, the staff revised the Program Description’s definition for an adverse localized environment.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, XI.E1, “Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” Element 1, “Program Description,” the adverse localized environment definition is revised to read “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 and connectors, including those that are coated with fire-retardant material.”

Associated technical basis for the Program Description change is included in the Technical Bases Document Supplement 1, Table 2-35, “GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” Section XI.E1, “Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.”

NRC ID: 30-002, AMS- XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," Various electrical AMPs, use of condition monitoring techniques to assess the aged condition of cable insulation materials.

Overview of Public Comment:

The comment recommends the use of condition monitoring techniques to assess the aged condition of cable insulation material in XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," XI.E2," Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits," XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," and XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Response:

While the staff recognizes that there have been advancements in technology for testing and monitoring cables and connections, the staff disagrees with the comment since specific condition monitoring techniques that may be capable of identifying and trending aging of cable insulation materials have not been sufficiently validated by the staff to permit exceptions for performing visual inspection of accessible in-scope cables and connections. The staff notes that the NRC has a research program to evaluate the current state-of-the art methods for testing and monitoring cables and connections. The results of this research program may inform future changes to the GALL-SLR Report.

Overview of Proposed Changes:

Not Applicable.

NRC ID: 30-003, AMS- Various electrical AMPs, clarification of existing maintenance, calibration, or surveillance programs that may be credited in lieu of testing.

Overview of Public Comment:

The comment recommends clarification of existing maintenance, calibration, or surveillance programs that may be credited in lieu of testing in XI.E1, "Electrical Insulation for Electrical Cables And Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," XI.E2, "Electrical Insulation For Electrical Cables And Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits," XI.E3B, "Electrical Insulation For Inaccessible Instrument And Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," and XI.E3C, "Electrical Insulation For Inaccessible Low Voltage Power Cables Not Subject to 10 FR 50.49 Environmental Qualification Requirements."

Response:

The staff partially agrees with the comment. The staff agrees that XI.E1, XI.E2, XI.E3B, and XI.E3C should be modified to clarify that calibration and surveillance testing programs can be credited if they can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope cables and connections used in instrumentation circuits. The staff also recognizes that certain activities do not directly assess the aged condition of the insulation of cables and should not be used to satisfy the intent of this AMP. The staff also agrees that technologies referenced in Regulatory Guide 1.218 include techniques for assessing and monitoring the aged condition of cable insulation such as polymer hardness measurements (e.g., indenter modulus (IM)), chemical analysis using infrared spectroscopy (e.g., Fourier transform infrared spectroscopy (FTIR)), polymer thermal property analysis (e.g., oxidation induction time and temperature (OIT/OITP)), and dielectric measurement techniques (e.g., frequency domain reflectometry). As the GALL-SLR AMPs associated with this comment already acknowledge RG 1.218 by reference, no further changes are necessary with respect to this part of the comment.

Overview of Proposed Changes:

In GALL-SLR, Volume 2, Revision 1, XI.E1, "Detection of Aging Effects," XI.E2, "Program Description," and "Detection of Aging Effects," XI.E3B, "Program Description," and "Detection of Aging Effects," XI.E3C, "Program Description," and "Detection of Aging Effects," are revised to clarify that calibration and surveillance testing programs can be credited if they can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope cables and connections used in instrumentation circuits. Modifications were also made to XI.E2 as a result of this comment since the incorporation of other modifications to XI.E2 sufficiently clarifies when calibration and surveillance testing programs can be credited.

Associated technical basis for the changes in the Program Descriptions and Detection of Aging Effects are included in the Technical Bases Document, Supplement 1, Table 2-35, "GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," sections XI.E1, XI.E2, XI.E3B, and XI.E3C.

NRC ID: 30-004, AMS- XI.E2, "Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits," use of insulation resistance testing for detecting age-related degradation of electrical cable insulations.

Overview of Public Comment:

The comment recommends the use of new techniques in addition to insulation resistance testing for detecting age-related degradation of electrical cable insulations in XI.E2, "Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,"

Response:

The staff agrees with the comment and implemented all recommended changes in the comment.

Overview of Proposed Changes:

GALL-SLR, Volume 2, Revision 1, Revise XI.E2 to clarify that users of the guidance should not rely solely on IR for assessing the condition of cable insulation and that a single test cannot on its own fully assess the aged condition of electrical cable insulation material. The staff also agrees that technologies referenced in Regulatory Guide 1.218 include techniques for assessing and monitoring the aged condition of cable insulation such as polymer hardness measurements (e.g., indenter modulus (IM)), chemical analysis using infrared spectroscopy (e.g., Fourier transform infrared spectroscopy (FTIR)), polymer thermal property analysis (e.g., oxidation induction time and temperature (OIT/OITP)), and dielectric measurement techniques (e.g., frequency domain reflectometry). As GALL-SLR AMP XI.E2 already acknowledges RG 1.218 by reference, no further changes are necessary.

The Detection of Aging Effects is revised to include the following:

> While insulation resistance testing is a recognized industry standard technique for determining the current condition of cable insulation, insulation resistance should not be used solely for detecting deterioration of electrical insulation systems since it is a pass/fail test that is not particularly sensitive to aging degradation of insulation materials. Therefore, a single insulation test cannot on its own fully assess the aged condition of electrical cable insulation material.

Associated technical basis for the change in the Detection of Aging Effects in included in the Technical Bases Document, Supplement 1, Table 2-35, “GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” Section XI.E2.

NRC ID: 30-005, AMS- XI.E1, “Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” Various electrical AMPs, evaluation of the condition of inaccessible electrical cables exposed to significant moisture.

Overview of Public Comment:

The comment recommends clarification of statements on the evaluation and condition of inaccessible electrical cables exposed to significant moisture in XI.E3A, “Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” XI.E3B, “Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” and XI.E3C, “Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.”

Response:

The staff disagrees with the comment as the point is already addressed in the program description of this AMPs. Specifically, the program description for these AMPs notes that the AMPs apply 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, instrument and control, and low-voltage cables that are within the scope of subsequent license renewal (SLR) and are potentially exposed to wetting or submergence (i.e., significant moisture). The word "potentially" was added in GALL-SLR Report, Revision 1 to address areas where cables were installed that could be subject to water accumulation or submergence. For those instances, the cables within the scope of these AMPs are expected to be treated as though they are continuously exposed to significant moisture.

Overview of Proposed Changes:

Not Applicable.

NRC ID: 30-006, AMS- XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements," clarification of expectations, which AMPs should be followed, and what actions should be taken for plants that have mostly inaccessible cables.

Overview of Public Comment:

The comment recommends clarification of expectations, which AMPs should be followed, and what actions should be taken for plants that have mostly inaccessible cables in XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements."

Response:

The staff disagrees with the comment. No modification is necessary for XI.E1 as in-scope inaccessible cables are addressed in GALL-SLR AMPs XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," and XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." These AMPs reference RG 1.218 which recognizes that condition monitoring techniques are available to monitor and assess insulation degradation in accessible and inaccessible cables.

Overview of Proposed Changes:

Not Applicable.

NRC ID: 30-007, AMS- XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," AMPs, visual inspection of age related degradation in cables located in harsh environmental conditions.

Overview of Public Comment:

The comment recommends for XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," provide additional guidance on how cables that cannot be visually inspected in the location of harshest environmental condition should be evaluated for age-related degradation.

Response:

The staff disagrees with the comment that additional guidance is necessary. The staff agrees that the locations where visual inspections can be performed on inaccessible and underground cables are limited and may not encompass the most severe environmental conditions to which cables are exposed. However, GALL-SLR AMPs XI.E3B and XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" currently require aging management of in-scope inaccessible cables to provide reasonable assurance that the intended functions of inaccessible or underground instrument and control cables and low-voltage cables. Specifically, the program description for these AMPs notes that the AMPs apply 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) instrument and control and low-voltage cables that are within the scope of subsequent license renewal (SLR) and are potentially exposed to wetting or submergence (i.e., significant moisture). The word "potentially" was added in GALL-SLR Report, Revision 1 to address areas where cables were installed that could be subject to water accumulation or submergence. For those instances, the cables within the scope of these AMPs are expected to be treated as though they are continuously exposed to significant moisture. Therefore, the proposed revision to GALL-SLR Report, Revision 1 will adequately address aging management of cables in all locations, including those in the harshest environmental conditions.

Overview of Proposed Changes:

Not Applicable.

NRC ID: 30-008, AMS-XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," and XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," periodic testing for evaluating the condition of a cable over time.

Overview of Public Comment:

AMS's comment provided a recommendation to replace the statement "to perform a one-time test" with "periodic testing" as a one-time test may not provide a suitable means of evaluating the condition of a cable over time in XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," and XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Response:

The staff disagrees with the comment. While the staff agrees that performing a one-time test may not provide a suitable means of evaluating the condition of a cable over time, the expectation for possibly needing to perform periodic testing is already captured in GALL-SLR AMPs XI.E3A, XI.E3B, and XI.E3C which note that the need for additional tests and inspections is determined by the test/inspection results as well as industry and plant-specific operational experience. The one-time test, where required, of inaccessible and underground instrumentation and control cables exposed to significant moisture, periodic actions to visually inspect accessible portions of the cables in manholes, vaults, or other underground raceways, and operational experience should collectively be considered to determine if additional testing is necessary to evaluate the condition of a cable over time.

Overview of Proposed Changes:

Not Applicable.

NRC ID: 30-009, AMS- XI.E7, "High Voltage Insulators," Allow for visual inspection alternatives, other test methods demonstrated to be effective in determining the aged condition of insulations.

Overview of Public Comment:

The comment recommends acknowledgement of other test methods that have been demonstrated to be effective in determining the aged condition of insulations that can be used to evaluate the health of high-voltage insulators along with or as an alternative to visual inspections in XI.E7, "High Voltage Insulators."

Response:

The staff partially agrees with the comment. The staff agrees that materials testing of polymeric high-voltage insulators, in addition to visual inspections, can provide significant insight into the aged condition of polymers and that there are a variety of methods for assessing the state of

polymeric materials. However, the staff disagrees with adding the statements proposed by the comment.

Overview of Proposed Changes:

GALL-SLR, Volume 2, Rev 1, XI.E7, “Detection of Aging Effects” is modified to recognize that visual inspections may be supplemented by other test methods that have been demonstrated to be effective in determining the age condition of insulators..

The Detection of Aging Effects is revised to include the following:

> Visual inspections may be supplemented with other test methods that have been demonstrated to be effective in determining the aged condition of insulators such as infrared thermography inspections to detect high-voltage insulator reduced insulation resistance.

Associated technical basis for the change in the Detection of Aging Effects in included in the Technical Bases Document, Supplement 1, Table 2-35, “GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” Section XI.E7.

NRC ID: 31-001, J. Gromatzky (ENERCON) - Confirm modification of AMR item II.A1.CP-68

Overview of Public Comment:

The comment seeks clarification in GALL-SLR Report Volume 1, Revision 1, Chapter II.A1, Table A1, “Concrete Containments (Reinforced and Prestressed),” AMR item “II.A1.CP-68,” which is identified as Modified (M) in the first column for this entry, however there is no apparent change between GALL-SLR Revision 0 and GALL-SLR Revision 1 for this item.

Response:

The staff agrees with the comment. Item “II.A1.CP-68,” was erroneously identified as Modified, “M” is removed from the first column. This item was not modified in GALL-SLR Revision 1.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 1, Revision 1, Chapter II.A1, Table A1, “Concrete Containments (Reinforced and Prestressed),” page. II-6, item “II.A1.CP-68,” M” is removed from the first column.

NRC ID: 31-002, J. Gromatzky (ENERCON) - Confirm modification of AMR item II.A1.CP-32 aging effect/mechanism.

Overview of Public Comment:

The comment recommends for AMR line Item II.A1.CP- 32, clarification or confirmation of the aging effect/mechanism for this item, which indicates, “Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation.” The comment focuses

on the significance of “and,” and requests to indicate if there should be an edited change to this item to change the word “and” to the word “or.”

Response:

The staff disagrees with the comment. The staff acknowledges that leaching of calcium hydroxide and carbonation are different aging mechanisms that can cause a loss of strength. However, the staff disagrees that “and” should be revised to “or” because the loss of strength could be caused by either leaching of calcium hydroxide, or due to carbonation, or a combination of both (as connoted by use of “and,” for the aging effect/mechanism description).

Overview of Proposed Changes:

Not applicable.

NRC ID: 31-003, J. Gromatzky (ENERCON) - Confirm AMR item II.A1.CP-32 carbonation as an applicable aging mechanism.

Overview of Public Comment:

The comment recommends for AMR Item II.A1.CP-32, clarification or confirmation of the aging effect/mechanism for this item, which indicates, “Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation.” The comment focuses on the significance of “carbonation.” Based on this description, the comment requests to indicate why carbonation is listed as an applicable aging mechanism for the identified environment of water–flowing for this item.

Response:

The staff disagrees with the comment. This environment/aging combination is dependent on the environment (water-flowing) for this line item. It is up to the licensee to evaluate whether this item is applicable to their site.

Overview of Proposed Changes:

Not applicable.

NRC ID: 31-004, J. Gromatzky (ENERCON) - Confirm AMR item II.A1.CP-147 applicable AMP/Time-Limited Aging Analysis (TLAA).

Overview of Public Comment:

The comment states for AMR Item II.A1.CP- 147, it is unclear what specific enhancements the NRC staff expects to see in either the XI.S2, "ASME Section XI, Subsection IWL" or XI.S6, "Structures Monitoring," programs if used to manage the aging of concrete due to the freeze-thaw aging mechanism. Clarification is requested of what specific enhancements are expected in either the XI.S2 or XI.S6 programs if used to manage the aging of concrete due to the freeze-thaw aging mechanism.

Response:

The staff disagrees with the comment. The commenter is referred to the related "Further Evaluation" Sections 3.5.2.2.1.7, "Loss of Material (Scaling, Spalling) and Cracking Due to Freeze-Thaw" and 3.5.3.2.1.7, "Loss of Material (Scaling, Spalling) and Cracking Due to Freeze-Thaw" of draft SRP-SLR (NUREG-2192), Volume 1, to determine whether a plant-specific program or enhancement to an existing program is necessary. Section 3.5.2.2.1.7 provides the acceptance criteria if a plant-specific program or enhancement is determined to be necessary. If determined to be necessary, the applicant's further evaluation will determine on a plant-specific basis what the plant-specific program or enhancement will be, and the NRC staff will review it against the acceptance criteria in the branch technical position in SRP-SLR Appendix A for AMP program elements.

Overview of Proposed Changes:

Not applicable.

NRC ID: 31-005, J. Gromatzky (ENERCON) - AMR item II.A1.CP-67 associated table formatting, row breaks across the bottom of pages and column headers.

Overview of Public Comment:

The comment recommends for Draft SLR-SLR, Revision 1, Table A.1, "Concrete Containments (Reinforced and Prestressed), AMR item II.A1.CP-67, associated table formatting, placement of row breaks across the bottom of pages and column headers.

Response:

The staff agrees with the comment. Table A.1, along with all tables in the GALL-SLR Report, Volume 1 and Volume 2, Revision 1, and Technical Bases Document, Supp. 1. will be revised to incorporate table titles and row headings on every page where the tables span more than one page.

Overview of Proposed Changes:

Globally, all tables in the SLR Guidance documents are revised to incorporate table titles and row headings on every page where the tables span more than one page.

NRC ID: 31-006, J. Gromatzky (ENERCON) - Confirm AMR item III.A4.TP-305 environment.

Overview of Public Comment:

The comment recommends for AMR Item III.A4.TP- 305, clarification of AMR item related to containment internal structures considered as exterior above and below-grade inaccessible areas, clarification of which containment internal structures are exposed to a water flowing environment, and clarification why containment foundation is included here when it appears to be addressed by other items in other tables.

Response:

The staff disagrees with the comment. The comment depends on the plant configuration. It is up to the applicant to determine whether the component, material, environment, and aging effect combination in the AMR line item exist in their specific plant.

Overview of Proposed Changes:

Not applicable.

NRC ID: 31-007, J. Gromatzky (ENERCON) - Confirm AMR item III.A4.T-36 environment.

Overview of Public Comment:

The comment recommends for AMR Item III.A4.T- 36, clarification of why is the environment for this item is listed as Air – indoor uncontrolled? The comment suggests that it may be more appropriate to identify the environment as Air – indoor uncontrolled, neutron flux.

Response:

The staff disagrees with the comment. The environment can be attributed in general as originally listed. Restricting the environment to neutrons will mask potential cumulative/combined aging effects on reactor vessel steel structural supports due to other environments, e.g., thermal, boric acid, etc.

Overview of Proposed Changes:

Not applicable.

NRC ID: 31-008, J. Gromatzky (ENERCON) - Requests for Additional Information (RAIs) on audit comments regarding the use of SRP-SLR and GALL-SLR item numbers from integrated plant assessment (IPA) sections which differ from IPA sections from AMR tables from license renewal applications.

Overview of Public Comment:

The comment noted that staff have on occasion written RAIs or made audit comments regarding the use of SRP-SLR and GALL-SLR item numbers from IPA sections that are different from the IPA section for an AMR table of an application (e.g., listing VII.C2.A-791 and 3.3-1, 257 for heat exchanger tubes in a component associated with the ESF IPA group rather than V.D2.EP-79 and 3.2-1, 051 or an equivalent item associated with the ESF IPA group). The comment is made even though there is no difference in material, environment, AERM, credited AMP, or lack of further evaluation required between the items. The comment recommends a discussion of the rationale for not consolidating these items into a single line item applicable to all listed IPA groups as this seems to be beneficial to both the applicant and NRC in reducing time spent on making what amounts to inconsequential distinctions.

Response:

Staff disagrees with the comment. When technical reviewers point out that a different GALL-SLR item number could have been used, this is just for clarification to anyone who might be reading the safety evaluation. The staff agrees that in general, these types of minor differences in an application should not result in a request for additional information for the applicant. The integrated plant assessment groups were developed in a systematic manner to ensure that all systems, structures, and components were captured in the integrated plant assessment. This structure is considered to have successfully supported clear, well-organized applications, and the effort required to consolidate the items and revise the subsequent license renewal process would not increase process efficiency.

Overview of Proposed Changes:

Not applicable.

NRC ID: 31-009, J. Gromatzky (ENERCON) - NRC staff expectations for SLR Guidance for first time license renewal applicants, additional updates to SRP (NUREG-1800) or GALL (NUREG-1801).

Overview of Public Comment:

Because the NRC is not updating first time license renewal guidance documents, NUREG-1800 Revision 2, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” (Agencywide Documents and Access Management System (ADAMS) Accession No. ML103490036) or NUREG-1801 Revision 2, “Generic Aging Lessons Learned (GALL) Report,” (ADAMS Accession No. ML103490041), but are expecting applicants for first time license renewal to address some changes that are in subsequent license renewal guidance documents, NUREG-2191 Revision 1, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,” (ADAMS Accession No. ML23180A182 and ML23180A188) and NUREG-2192 Revision 1, “Standard Review Plan for Review of Subsequent License Renewal

Applications for Nuclear Power Plants," (ADAMS Accession No. ML23180A191), the NRC staff should clearly identify which items in these documents need to be addressed by first time license renewal applicants.

Response:

- The staff disagrees with the comment. The staff determined that the resources needed to make the proposed revisions are not justified, as the applicability may be limited to only one potential renewal applicant at the time of the issuance of this update. Rather, direct communications with that applicant can address any needed guidance clarifications. Long-term considerations on initial renewal guidance (i.e., for potential renewal of Vogtle Units 3 and 4 several years in the future) are considered to be most appropriately addressed closer to the time of those applications.
- At the time of the anticipated issuance of this guidance revision, there will only be one remaining nuclear power plant that had yet to submit an initial license renewal application. New units at Plant Vogtle (Units 3 and 4) could potentially come in for license renewal 20 years prior to the expiration of their initial operating licenses, also. The NRC staff determined that, given the small pool of license renewal applicants, the interim staff guidance (ISG) currently in effect, the lengthy process to update guidance, the NRC staff's workload, and the fact that guidance updates are at this point highly plant specific depending on operating experience, an update to Revision 2 of NUREG-1800 and NUREG-1801 was not worth the effort. The list of current ISGs is found at https://www.nrc.gov/reading-rm/doc-collections/isg/license-renewal.html.
- Applicants for initial license renewal may need to consider the latest guidance in Revision 1 of NUREG-2191 or NUREG-2192 if necessitated by:
  - changes in operating experience for which relevant updated guidance is available,
  - updates to relevant industry codes and standards that are endorsed by the NRC staff,
  - new NRC staff approved and relevant topical reports,
  - new relevant research and development.

  In most of these cases the SLR guidance that needs to be considered is highly plant specific and dynamic depending on recent operating experience. It is therefore not feasible, or not effective, to create a static list of items in Revision 1 of NUREG-2191 or NUREG-2192 that need to be considered by initial license renewal applicants.
- Pre-application correspondence, engagements, and early coordination by initial license renewal applicants and the NRC Staff have proved to be highly beneficial towards ensuring an efficient and predictable review. Initial license renewal applicants are encouraged to work with their license renewal Project Managers not only on planning and logistics for the application but also to engage the technical staff on the areas where additional or updated guidance may be available, particularly within Revision 1 of NUREG-2191 or NUREG-2192.

Overview of Proposed Changes:

Not applicable.

NRC ID: 31-010, J. Gromatzky (ENERCON) - GALL-SLR, Volume 1, Chapter VII, Auxiliary Systems, Table B, "Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," the entry for Item VII.B.A-07 contains an editorial error.

Overview of Public Comment:

The comment recommends correction of an editorial error in GALL-SLR, Volume 1, Chapter VII Auxiliary Systems, Table B.1, "Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." The entry for Item VII.B.A-07 contains an editorial error. In the column, "Aging Effect/Mechanism," the commas should be replaced with semicolons to indicate independent aging effects.

Response:

The staff agrees with the comment. Editorial corrections will be made in the text.

Overview of Proposed Changes:

In GALL-SLR, Volume 1, chapter VII Auxiliary Systems, Table B.1, "Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," the entry for Item VII.B.A-07 contains an editorial error. In the column, "Aging Effect/Mechanism," the three commas are replaced with semicolons.

In SRP-SLR, in Table 3.3-1, "Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the Generic Aging Lessons Learned for Subsequent License Renewal Report (Continued)," the entry for Item VII.B.A-07 contains an editorial error. In the column, "Aging Effect/Mechanism," the three commas are replaced with semicolons.

NRC ID: 31-011, J. Gromatzky (ENERCON) - SRP-SLR, Table 3.5-1, "Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR Report)" item 027, clarification of the AMP column, which indicates AMP XI.S1 "ASME Section XI, Subsection IWE" and AMP XI.S4, 10 CFR Part 50, Appendix.

Overview of Public Comment:

The comment recommends for Draft SRP-SLR, Revision 1, Table 3.5-1, "Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR Report)," Item 027, clarification of the AMP column, which indicates AMP XI.S1 "ASME Section XI, Subsection IWE" and AMP XI.S4, "10 CFR Part 50, Appendix J." Confirm the word "and," or shall it be changed to "or."

Response:

The NRC staff agrees with the comment because the recommended change in the comment is consistent with the provisions in the "Detection of Aging Effects" program element of GALL-SLR AMP XI.S1 to manage the aging effect of cracking due to cyclic loading when CLB fatigue

analysis does not exist. The AMP provision recommends that this aging effect may be managed by supplementing the XI.S1 AMP to perform surface examination (or other applicable technique) capable of detecting cracking due to cyclic loading for each of the specific components OR where feasible by performing appropriate 10 CFR Part 50, Appendix J (AMP XI.S4) local leak rate tests capable of detecting cracking.

Overview of Proposed Changes:

Draft GALL-SLR Report (NUREG-2191), Volume 1, Revision 1, Table B.7, "Common Components," column, "Aging Management Program (AMP)/Time-limited aging analysis (TLAA)," Items II.A3.CP-37, II.B1.1.CP-49, II.B2.1.CP-107, and II.B4.CP-37, are revised to change the word from "and" to "or."

Associated technical basis for the changes are added to the Technical Bases Document, Supp. 1, Table 2 19, "Changes to GALL-SLR Report, Revision 0, Chapter II Aging Management Review Items and Technical Bases," for items II.A3.CP-37, II.B1.1.CP-49, II.B2.1.CP-107, and II.B4.CP-37.

Draft SRP-SLR, Revision 1, Table 3.5 1, "Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR Report), "Item 027, column "Aging Management Program (AMP)/Time-Limited Aging Analysis (TLAA)," is revise from "and" to "or."

Associated technical basis for the changes are added to the Technical Bases Document, Supp. 1, Table 3 7, "SRP-SLR, Revision 1, Chapter 3.5, Containments, Structures, and Component Supports, Differences from SRP-SLR, Revision 0, and Their Technical Bases," for Table 3.5-, Item 027.

NRC ID: 31-012, J. Gromatzky (ENERCON) - Swapping the order of SRP-SLR sections to allow Group IV "Containment Internal Structures," to flow from one to the other.

Overview of Public Comment:

The comment recommends swapping the order of SRP-SLR sections, 3.5.2.2.2.7, "Loss of Material, and/or Changes in Material Properties Due to Weathering, Chemical Degradation, Insect Infestation, Repeated Wetting and Drying, or Fungal Decay," and 3.5.2.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete," to allow Group IV "Containment Internal Structures," to flow from one to the other and are not separated by an unrelated further evaluation section.

Response:

The staff disagrees with the comment. While the ordering may be better for content flow those benefits are outweighed by the potential for confusion among staff and industry stakeholders. SRP-SLR Section 3.5.2.2.2.8, is referred to in two other sections of the SRP-SLR, Revision 1, is the subject of seven public comments in this round of updates, and is widely recognized. Putting this content under Section 3.5.2.2.2.7 could potentially cause confusion requiring additional explanation within the guidance.

Overview of Proposed Changes:

Not applicable.

NRC ID: 31-013, J. Gromatzky (ENERCON) - SRP-SLR Section 3.5.2.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete," revise as loss of material of carbon or low alloy steel is not associated with irradiation but with a corrosive environment.

Overview of Public Comment:

The comment recommends that SRP-SLR further evaluation (FE) Section 3.5.2.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other reactor vessel (RV) Structural Support Components That are Not Concrete," be revised as loss of material of carbon or low alloy steel is not associated with irradiation but with a corrosive environment, such as potential boric acid buildup.

Response:

The staff disagrees with the comment. Staff's disagreement rests on the prerequisite to the use of NUREG-1509 as an evaluation tool with regard to the effects of radiation of the RV supports is a "physical examination" to detect visible signs of degradation, including, but not limited to "rust, corrosion, cracks or permanent deformation of the members." If there is no "physical examination" then the use of NUREG-1509 for this FE evaluation is questionable. The applicant then needs to propose its own approach which the staff will review for acceptability.

Furthermore, the staff disagrees on the cumulative effects of aging due to combined aging mechanisms that affect RV structural steel support assembly. Rust, corrosion, cracks, or permanent deformation of the members will affect the load bearing capacity of the RV structural steel support assembly. Bearing capacity of the RV structural steel support assembly. Applicants, consistent with 10 CFR 54.21(a)(3), must demonstrate that the cumulative effects of aging to combined aging mechanisms will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-000, Andrew N. Mauer (NEI) – License Renewal Application and Subsequent License Renewal Application future workload necessitates increased efficiency of application reviews, particularly removal of opportunistic inspections, prescriptive actions.

Overview of Public Comment:

The comment states, “consistent with the NRC’s Principles of Good Regulation, the NRC should not only ensure safety but operate efficiently as well, so that regulatory activities are consistent with the degree of risk reduction they achieve.” The comment provided recommendations that affect multiple review areas within the License Renewal Application (LRA) and Subsequent License Renewal (SLRA) guidance, to include removal of opportunistic inspections and removal of prescriptive corrective actions.

Response:

The staff disagrees with the comment and the suggested recommendations in the comment. However, the staff does agree with the intent of the comment, which is to implement efficiencies in the LRA/SLRA review process.

On March 28, 2024, the NRC staff issued SECY-24-0026, “Achieving Timely Completion of License Renewal Safety and Environmental Reviews (License Renewal Roadmap)” (ADAMS Accession No. ML24059A131), as supplemented on April 15, 2024 (ADAMS Accession No. ML24101A364), highlighting the staff’s goals of timely and predictable 18-month reviews, while reducing resources.

As part of the License Renewal Roadmap, the staff has outlined a 3-phase approach to improve the efficiency of the safety review:

- Phase 1, “Process Improvements,” was completed on March 28, 2024. It comprised of seven process improvement initiatives that leverage best practices from new and advanced reactor reviews that have contributed to timely and cost-effective safety decisions. Additional information on Phase 1 can be found in SECY-24-0026, Appendix D, Table D-2.
- Phase 2, “Tiered Approach,” was implemented April 2024. The Tiered Approach tailors the level of staff’s review by incorporating risk insights, leveraging operating programs, previous reviews, NRC and industry operating experience with aging management, and taking into consideration consistency with NRC guidance documents. Additional information on Phase 2 can be found in SECY-24-0026, Appendix C.
- Phase 3, “Additional Process Improvements,” targeted for implementation by December 2024, will optimize audits, safety evaluations, and leverage information technology to improve efficiency. Additional information on Phase 3 can be found in SECY-24-0026, Appendix D, Table D-3.

Since August 2023, the NRC staff has held 5 public meetings with external stakeholders to discuss methods to improve the LR process, with the next public meeting scheduled for June 2024. As part of the License Renewal Roadmap, the staff has engaged with the industry regarding staggering the timing of application submittals (1 application every 3 months) to aid with workload management and schedules to support 18-month reviews.

In terms of removal of prescriptive corrective actions see staff’s responses for comments 6, 8, 10, 15, 16, and 18.

In terms of removal of opportunistic inspections see staff's responses for comments 32-013, 32-016, 32-021, 32-022, and 32-054.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-001, Andrew N. Mauer (NEI) – Table IX.E, "Aging Effects," removal of cracking as an applicable aging effect for CFRP.

Overview of Public Comment:

The comment recommends removing cracking as an applicable aging effect for CFRP (including in applicable GALL-SLR and SRP-SLR line items,) and deletion of the second paragraph in the Cracking definition in Table IX.E. The updated cracking definition provided in Table IX.E states that cracking of CFRP is caused by delamination or disbonding. Delamination or disbonding of CFRP is caused by improper installation/quality control and is not caused by aging. If the recommendation for removal is not accepted, the comment recommends providing operating experience or a technical basis indicating age-related delamination or disbonding of CFRP results in cracking.

Response:

The staff disagrees with the comment. The staff notes that exposure to environmental effects such as temperature and/or moisture can cause degradation of epoxy resin matrix in CFRP composite. Degradation of matrix can result in cracking of fiber-matrix interfacial bonding, delamination of layers, lowering matrix glass transition temperature, swelling of matrix, and microcracking of matrix (MIL-HDBK-17). CFRP is brittle. As such, cracking may occur.

Overview of Proposed Changes:

Not applicable.

References:

MIL-HDBK-17, "Composite Materials Handbook, Volume 1. Polymer Matrix Composites Guidelines for Characterization of Structural Materials." https://indico.fnal.gov/event/13241/contributions/18146/attachments/12002/15271/MIL_Handbook_17.pdf, June 17, 2002 DOD 2002-TN10078

NRC ID: 32-002, Andrew N. Mauer (NEI) – Table IX.E, "Aging Effects," removal of flow blockage as an applicable aging effect for CFRP.

Overview of Public Comment:

The comment recommends removal of flow blockage as an applicable aging effect for CFRP (including in applicable GALL-SLR and SRP-SLR line items), and the reference to delamination or disbonding of CFRP be removed from the flow blockage definition in Table IX.E "Aging Effects." Delamination or disbonding of CFRP is caused by improper installation/quality control and is not caused by aging. One of the benefits of installing HDPE and CFRP is improved flow rates and resistance to flow blockage due to fouling. If the recommendation for removal is not accepted, the comment requests providing OE or technical basis indicating age-related delamination or disbonding of CFRP results in flow blockage.

Response:

The staff disagrees with the comment. Flow blockage is an effect which can occur due to fouling and delamination and debonding of CFRP repaired piping. For CFRP-repaired pipe, flow blockage can occur due to delamination and debonding of the CFRP. AMP XI.M43, Element 10, "Operating Experience," describes an operating experience where a section of CFRP layers was completely missing from the pipe surface. The CFRP debris were found at the metallic screens (strainer) inside of the pipe.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-003, Andrew N. Mauer (NEI) - Table IX.E, "Aging Effects," removal of the reference to delamination or disbonding of CFRP from the loss of material definition.

Overview of Public Comment:

The comment recommends removal of the reference to delamination or disbonding of CFRP from the loss of material definition. The updated definition states that loss of material of CFRP can be caused by delamination or disbonding. Delamination or disbonding of CFRP is caused by improper installation/quality control and is not caused by aging. If the recommendation for removal is not accepted, the comment recommends providing OE or technical basis indicating age-related delamination or disbonding of CFRP results in loss of material.

In addition, the comment recommends removal of the reference to environmental exposure for polymeric materials from the loss of material definition. The updated loss of material definition states that loss of material of CFRP can also be caused by environmental exposure (e.g., chemical attack, moisture). Degradation of polymeric materials, including HDPE and CFRP, due to environmental exposure does not occur if the correct material is selected for the modification (i.e., this is a design issue and not an aging issue). If the recommendation for removal is not accepted, the comment recommends providing OE or technical basis indicating age-related degradation of polymeric materials occurs due to environmental exposure when the correct material is selected for the environment.

Response:

The staff disagrees with the comment. The staff determined that loss of material for CFRP-repaired piping can occur from delamination and debonding. Exposure to environmental effects such as temperature and/or moisture can cause degradation of epoxy resin matrix in CFRP composite. Degradation of matrix will result in cracking of fiber-matrix interfacial bonding, delamination of layers, lowering matrix glass transition temperature, swelling of matrix, and microcracking of matrix. Loss of material due to exposure to temperature or moisture can result from delamination of layers. For CFRP, flow blockage can occur due to delamination or debonding of the CFRP.

For HDPE, degradation of or loss of materials due to environmental effects can occur if the incorrect material is selected, or if an improper fusion butt joint or electrofused joint is performed.

The staff notes that it is difficult to determine whether the degradation is caused by aging, improper installation, or a combination of both. The degradation in CFRP-repaired piping and HDPE piping need to be monitored and managed.

Overview of Proposed Changes:

Not applicable.

References:

PVP2008-61906, "Tensile Testing and Material Property Development of High Density Polyethylene Pipe Materials" https://doi.org/10.1115/PVP2008-61906, July 24, 2009. ASME 2008-TN10987

NRC ID: 32-004, Andrew N. Mauer (NEI) - XI.M9 "BWR Vessel Internals," reference to correct EPRI report on fracture toughness threshold relative to fluence.

Overview of Public Comment:

Table G.1, "Fire Protection," AMR item VII.G.A-789, stress corrosion cracking (SCC) applies only to stainless steel as described in the Technical Bases Document, Supplement 1, Table 2-10, "New Aging Management Review Items Added in GALL-SLR Report Revision 1, Chapter VII, Auxiliary Systems." The comment recommends adding clarification that SCC applies only to stainless steel for this item.

Response:

The staff agrees with the comment. VII.G.A-789 is actually described in the Technical Bases Document, Supplement 1, Table 2-24, "Changes to GALL-SLR Report, Revision 0, Chapter VII Aging Management Review Items Technical Bases." As noted in Table 2-24, fire damper housings are typically constructed of steel or stainless steel. The staff agrees that SCC would not be an applicable aging effect for steel fire damper housings; however, it would be an applicable aging effect for stainless steel fire damper housings. AMR item VII.G.A-789, 3.3-1, 255 is revised in GALL-SLR Volume 1, Revision 1; SRP-SLR, Revision 1; and Technical Bases

Document, Supplement 1, to reflect that SCC applies only to stainless steel fire damper housings.

Overview of Proposed Changes:

In GALL-SLR Volume 1, Revision 1, Table G.1, "Fire Protection," revise item VII.G.A-789, Item 3.3-1, 255, aging effect/mechanism to reflect Loss of material due to general, pitting, crevice corrosion; cracking due to stress corrosion cracking (SCC) (Stainless steel only).

In SRP-SLR, Revision 1, Table 3.3-1, "Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the Generic Aging Lessons Learned for Subsequent License Renewal Report," revise the aging effect/mechanism for ID 255 as follows: Loss of material due to general, pitting, crevice corrosion; cracking due to SCC (stainless steel only).

Technical Bases Document, Supplement 1, Table 2-24, "Changes to GALL-SLR Report, Revision 0, Chapter VII Aging Management Review Items Technical Bases," Item No. VII.G.A-789, clarification is added that the SCC applies only to stainless steel fire damper housings.

NRC ID: 32-005, Andrew N. Mauer (NEI) - XI.M9 "BWR Vessel Internals," reference to correct EPRI report on fracture toughness threshold relative to fluence.

Overview of Public Comment:

The comment recommends XI.M9, "BWR Vessel Internals," to reference the correct EPRI report on fracture toughness threshold relative to fluence.

Response:

The NRC staff partially agrees with the comment. The EPRI document recommended by the commenter is actually a presentation, which is a useful addition to support the aging management program description. However, the NRC should retain the original reference rather than replace it, in order to document the public meeting.

Overview of Proposed Changes:

In GALL-SLR Volume 2, Revision 1, XI.M9, "BWR Vessel Internals," Item 1, "Scope of Program," the NRC staff added reference to ADAMS Accession No. ML21147A008 (NRC 2021-TN10077), which is an EPRI presentation describing recommended fluence thresholds for vessel internals flaw evaluations.

The following reference was added to GALL-SLR "BWR Vessel Internals:"

EPRI Presentation, "Potential Non-Conservatism in EPRI Report, BWRVIP-100, Revision 1-A, and EPRI's Software, BWRVIP-235," Electric Power Research Institute, May 27, 2021, ADAMS Accession No. ML21147A008.

In Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From

GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M9, "BWR Vessel Internals," associated technical basis is added for the addition of the reference.

NRC ID: 32-006, Andrew N. Mauer (NEI) - XI.M9 "BWR Vessel Internals," addition of reference to BWRVIP-58-A.

Overview of Public Comment:

The comment recommends in XI.M9, "BWR Vessel Internals," the addition of references to BWRVIP-58-A, which provides guidelines for Control Rod Drive internal access weld repairs, used for design repairs guidelines.

Response:

The NRC disagrees with the comment. BWRVIP-58-A is already referenced in GALL-SLR XI.M8, "BWR Penetrations." XI.M8 is the more appropriate AMP for this topical report, since the repair technique described in BWRVIP-58-A is applied to reactor pressure vessel bottom head penetration nozzles.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-007, Andrew N. Mauer (NEI) - XI.M9 "BWR Vessel Internals," revision of reference to BWRVIP-84 to the latest version, revision 3.

Overview of Public Comment:

The comment recommends for XI.M9 "BWR Vessel Internals," revision of reference to BWRVIP-84 to the latest version, Revision 3.

Response:

The NRC disagrees with the comment. The BWRVIP may not submit all updated topical reports for NRC review. For example, the BWRVIP may invoke NEI 03-08, Appendix C, "Document Screening" to determine that NRC review is not necessary. As such, NRC staff does not have access to all updated proprietary BWRVIP reports. Since BWRVIP-84, Revision 3 is not docketed with the NRC, the staff cannot endorse it's use in GALL-SLR.

The NRC currently endorses BWRVIP-84, Revision 2-A in AMP XI.M9 for repair of BWR vessel internals components. While the NRC received a public comment suggesting that NRC endorse BWRVIP-84, Revision 3, the staff notes that the BWRVIP has not submitted BWRVIP-84, Revision 2-A to NRC for review. For example, the BWRVIP may invoke NEI 03-08, Appendix C, "Document Screening" to determine that NRC review is not necessary. Since BWRVIP-84, Revision 3 is not docketed with the NRC, the staff cannot endorse it's use in GALL-SLR.

Overview of Proposed Changes:

Not applicable.

References:

BWRVIP-84, Revision 2-A (EPRI 3002007385NP), "BWR Vessel and Internals Project, Guidelines for Selection and Use of Materials for Repairs to BWR Internal Components." Palo Alto, California: Electric Power Research Institute. April 2016 (ADAMS Accession No ML16138A386).

BWRVIP-84, Revision 3 (EPRI 3002010552), "BWR Vessel and Internals Project, Guidelines for Selection and Use of Materials for Repairs to BWR Internals Components." Palo Alto, California: Electric Power Research Institute. November 2017.

NRC ID: 32-008, Andrew N. Mauer (NEI) - XI.M9 "BWR Vessel Internals," revision of reference to BWRVIP-18 to the latest version, revision 2A.

Overview of Public Comment:

The comment recommends to update XI.M9, "BWR Vessel Internals," reference from BWRVIP-18, Revision 1-A to BWRVIP-18, Revision 2-A.

Response:

The NRC agrees with the comment. BWRVIP-18, Revision 2-A was reviewed and approved by the NRC through the topical report process. In addition, BWRVIP-18, Revision 2-A is the referenced revision elsewhere in XI.M9. Therefore, it is appropriate for the NRC to update the outdated reference to BWRVIP-18, Revision 1-A to Revision 2-A.

Overview of Proposed Changes:

In GALL-SLR, Volume 2, Revision 1, XI.M9, "BWR Vessel and Internals," Item 10, "Operating Experience," the reference to BWRVIP-18, Revision 1-A (EPRI 1025060) is changed to Revision 2-A (EPRI 3002008089. In addition in the BWRVIP-18 Revision 2-A entry is updated in the References section.

In the Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," XI.M9, "BWR Vessel and Internals, technical bases was added for the reference update.

References:

BWRVIP-18, Revision 1-A (EPRI 1025060), "BWR Vessel and Internals Project, BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines." Palo Alto, California: Electric Power Research Institute. April 2012. EPRI 2012-TN10994

BWRVIP-18, Revision 2-A (EPRI 3002008089), “BWR Vessel and Internals Project, BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines.” Palo Alto, California: Electric Power Research Institute. August 2016. EPRI 2016-TN8302

NRC ID: 32-009, Andrew N. Mauer (NEI) - XI.M12 “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel,” revision to ASME Section XI surface examination of valve bodies.

Overview of Public Comment:

The commenter requests to delete the third sentence in the first paragraph on page XI-111. which is related to GALL-SLR AMP XI.M12. The comment states that the ASME Code, Section XI no longer requires surface examination of valve bodies less than 4 inches NPS.

Response:

The staff agrees with the comment. The sentence suggesting that ASME Code, Section XI requires surface examination of valve bodies less than 4 inches NPS is incorrect and should be deleted. The surface examination requirements were deleted, in the 2008 addenda and later Editions of the ASME Section XI.

Overview of Proposed Changes:

For GALL-SLR, Volume 2, Revision 1, AMP XI.M12, Scope of Program, paragraph 5, the sentence referencing surface examination of valve bodies less than 4 inches is deleted. Specifically, the following sentence is deleted, “ASME Code, Section XI, Subsection IWB requires only surface examination of valve bodies less than 4 inches NPS.”

NRC ID: 32-010, Andrew N. Mauer (NEI) - XI.M17 “FAC,” removal of reference to exclusion criteria for erosion, as discussed in LR-ISG-2012-01, erosion is associated with improper operation and is a design issue rather than an aging issue.

Overview of Public Comment:

The commenter requests that AMP XI.M17, “FAC” be revised to remove reference to an erosion susceptibility analysis. The comment noted that reliance on such an analysis was contrary to the guidance in LR-ISG-2012-01 and would lead to overly broad and unfocused results.

Response:

The staff disagrees with Comment 32-010. LR-ISG-2012-01 was issued in early 2013 to eliminate a recurring exception being taken by applicants to XI.M17 for use of the flow-accelerated corrosion AMP to also manage loss of material caused by erosion mechanisms. The first sentence of the program description notes that this was applicable to wall thinning due to erosion mechanisms that are not being managed by another program. At the time LR-ISG-2012-01 was issued, the industry had not published any specific guidance

regarding a program for managing erosion mechanisms, comparable to a program for managing the flow-accelerated corrosion mechanism.

The staff notes that several utilities have chosen to implement EPRI's guidance for the development of such erosion mechanism programs. The staff reviewed this guidance, as part of its prior license renewal activities, and found it to be an acceptable approach, stating in the proposed revision to XI.M17 that "erosion susceptibility screening, as provided in EPRI 3002005530, can augment erosion location identification." Making this statement is not contrary to the guidance contained in LR-ISG-2012-01. The intent of an erosion susceptibility analysis is to focus any inspection activities on the most likely locations. If the commenter believes that reliance on an erosion susceptibility analysis is not a reasonable approach, then this appears to be an issue to be addressed through EPRI.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-013, 32-016, 32-021, 32-022, 32-054, Andrew N. Mauer (NEI) - Removal of opportunistic inspections whenever components are accessible for several AMPs.

Overview of Public Comment:

The NEI Comments listed above request removal of the recommendation to perform opportunistic inspections whenever components are made accessible, which is currently in the GALL-SLR guidance for AMPs XI.M17 "Flow Accelerated Corrosion," XI.M18 "Bolting Integrity," XI.M21A "Closed Treated Water Systems," XI.M24 "Compressed Air Monitoring," and XI.M38 "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." Narrative 2 of the NEI comment document states that since the NRC already recommends a minimum required sample size for inspections, this minimum sample size provides the basis for reasonable assurance that aging will be adequately managed to ensure intended functions are maintained consistent with the station's current licensing basis through the period of extended operation. In addition, Narrative 2 discusses the logistical challenges of meeting the opportunistic inspection metric whenever system maintenance is performed. The inspections recommended in the various AMPs cannot be performed opportunistically using typical work planning processes at stations but rather must be specially planned because the inspections are not general, visual, skill-of-the-craft inspections performed during normal maintenance activities or other field work but instead, require work orders to include inspection instructions, documentation requirements, and potentially require personnel with specific qualifications who may not be involved in the scheduled activity.

Response:

The NRC staff agrees with the public comments and recommends removal of opportunistic inspections from the XI.M17 "Flow Accelerated Corrosion," XI.M18 "Bolting Integrity," XI.M21A "Closed Treated Water," XI.M24 "Compressed Air Monitoring," and XI.M38 "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" AMPs. While the specific environments vary for the components covered by these AMPs, there are some common themes such as 1) there are recommended minimum sample sizes in the AMPs (or in referenced industry standards (e.g., NSAC-202L)) that already provide reasonable assurance

that aging will be adequately managed to ensure intended functions are maintained consistent with the station's current licensing basis through the period of extended operation, 2) opportunistic inspections cannot always be performed within normal work planning practices, 3) performing opportunistic inspections can result in redundant inspection of certain components, which results in 4) taxation of limited station resources from other, higher-priority work.

For comment 32-016, the word “opportunistic” can be removed from AMP XI.M18, “Detection of Aging Effects,” because the guidance stated therein is intended to address the case when the specified minimum sample size cannot be met.

Overview of Proposed Changes:

In GALL-SLR Report Volume 2, Revision 1, opportunistic inspections, related references and guidance is eliminated from the following sections:

- XI.M17, “Flow Accelerated Corrosion,” Parameters Monitored or Inspected, Detection of Aging Effects,
- XI.M18, “Bolting Integrity,” Detection of Aging Effects,
- XI.M21A, “Closed Treated Water,” Detection of Aging Effects
- XI.M24, “Compressed Air Monitoring,” Program Description, Parameters Monitored or Inspected, Detection of Aging Effects,
- XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” Detection of Aging Effects, Corrective Actions,
- Table IX.D, “Use of Terms for Environments,” Air–dry,
- Table XI-01, “FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs,” XI.M24, XI.M38.

The purpose of these changes are to increase the efficiency of inspections performed during the subsequent period of extended operation by eliminating opportunistic inspections, since minimum sample size requirements for each population establish reasonable assurance and obviate the need for further opportunistic inspections.

Associated technical basis for the elimination of opportunistic inspections and related references and guidance are included in the Technical Bases Document Supplement 1, Table 2-33, “GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” sections XI.M17, XI.M18, XI.M21A, XI.M24, and XI.M38.

NRC ID: 32-015, Andrew N. Mauer (NEI) - XI.M17, "Flow Accelerated Corrosion," clarify periodic monitoring guidance for components where erosion is identified and the component is replaced with a more resistant material.

Overview of Public Comment:

The comment requests that AMP XI.M17 be clarified regarding periodic monitoring for component replacements with a material that is more resistant to erosion. The comment noted that if follow-up inspections demonstrate that the service life of the component extends beyond the end of the period of extended operation, then further inspections are not warranted.

Response:

The staff agrees with Comment 32-15. Similar to the existing corrective action discussion (about verifying the effectiveness of any operational parameter adjustments or components' geometric design changes to eliminate the cause an erosion mechanism), periodic monitoring of replacement materials can be stopped, after sufficient follow-up inspections have been performed to demonstrate that the more resistant material effectively mitigates the loss of material through the end of the extended operation period. However, this would not be applicable where the more resistant material is a coating or lining applied to components' surfaces. Periodic monitoring of the coatings or linings, comparable to that provided in XI.M42, should continue.

Overview of Proposed Changes:

The staff revised GALL-SLR, Volume 2, Revision 1, AMP XI.M17, "Corrective Actions" program element, third paragraph to clarify that periodic monitoring of components replaced with a material that is more resistant to erosion mechanism can be discontinued if sufficient inspections establish that the new material adequately mitigates the associated loss of material through the end of the period of extended operation.

NRC ID: 32-018, Andrew N. Mauer (NEI) - XI.M18, "Bolting Integrity," removal of guidance related to cracking of high-strength bolting from various AMPs.

Overview of Public Comment:

The comment recommends for XI.M18, "Bolting Integrity," XI.S1, "ASME Section XI, Subsection IWE," XI.S3, "ASME Section XI, Subsection IWF," and XI.S6, "Structures Monitoring," removal of guidance related to cracking of high-strength bolting from various AMPs.

Response:

The staff disagrees with the comment. High strength bolting is known to have greater susceptibility to stress corrosion cracking, and monitoring for cracking and the use of lower strength bolts are considered to remain widely-held good practices. GALL-SLR Report (NUREG-2191), Volume 2, Revision 1, XI.S3, Element 3, "Parameters monitored or inspected," states, "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." SRP-SLR (NUREG 2192), Revision 1,

Appendix A.1.2.1, “Applicable Aging Effects,” Item 1, states in part, “. . .and other relevant information should be considered in identifying applicable aging effects.”

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-019, Andrew N. Mauer (NEI) - XI.M2, “Water Chemistry,” removal of references to specific revisions of EPRI Reports as power plants typically commit to implement the latest water chemistry guidelines.

Overview of Public Comment:

Comment recommends removal of XI.M2, “Water Chemistry,” reference to specific revisions of EPRI Reports 3002002623, 3002000505, and 3002010645. Comment further states that stations typically commit to implement the latest water chemistry guidelines, and referencing the specific guidelines leads to unnecessary exceptions to GALL-SLR guidance when later versions are released.

Response:

The NRC does not agree with the changes suggested in the comment. The comment refers to the EPRI BWR water chemistry guidelines BWRVIP-190, Revision 1 (3002002623), Revision 7 of the PWR primary water chemistry guidelines (3002000505), and Revision 8 of the PWR secondary water chemistry guidelines (3002010645). The NRC recognizes that licensees typically commit to implementing updated versions of water chemistry guidelines. For example, all PWR licensees are required through their participation in the Steam Generator Management Program to implement the latest versions of the EPRI primary and secondary water chemistry guidelines, and associated interim guidance, within a specific period.

However, the NRC makes deliberate decisions about incorporating updated industry guidelines into NRC guidance based on an understanding that the changes reflect factors such as operating experience and best practices. Although the NRC does not review and approve the PWR or BWR water chemistry guidelines referenced in AMP XI.M2, the NRC maintains an awareness of changes to the guidelines through periodic meetings with industry and review activities. The NRC may decide not to incorporate an updated guideline into an AMP or may incorporate an updated guideline with limitations into an AMP. Thus, general NRC acceptance of industry guidelines would effectively preclude NRC’s review of any updated guidelines. The NRC notes that it may review and approve exceptions of this type, and the NRC does not agree with the comment that the exceptions are unnecessary.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-020, Andrew N. Mauer (NEI) - XI.M21A, "Closed Treated Water Systems," removal of inspection guidance that relies on control of chemistry parameters and use of corrosion inhibitors and biocides to prevent age-related degradation, and sampling of closed-cycle cooling water for iron and copper content.

Overview of Public Comment:

Comment recommends for XI.M21A, "Closed Treated Water Systems," removal of inspection guidance that relies on control of chemistry parameters and use of corrosion inhibitors and biocides to prevent age-related degradation. Sampling of closed-cycle cooling water for iron and copper content effectively monitors for any unexpected corrosion and can detect less than one gram of iron or copper in the process fluid. Further, these systems typically include corrosion monitoring stations to directly monitor corrosion rates in the system. As a closed system, the heat exchanger inspections typically performed provide a final backstop to detect any corrosion occurring in the system. Since it is a closed system, if any significant corrosion were occurring in the system, there would be corrosion product deposits on all internal surfaces. Thus, if corrosion were occurring in other parts of the system, away from the heat exchangers, this would still be detected through heat exchanger inspections. The recommended internal inspections are not necessary to ensure intended functions are maintained.

Response:

The staff disagrees with the comment, of removing the internal inspections recommended in the Closed Treated Water Systems AMP. The technical basis for these inspections was discussed in the Technical Bases Document (initial report), which documented the potentially severe conditions that led to stress corrosion cracking at heat exchanger surfaces based on OE (LER 263/2014-001). In addition, recent OE was found of recurring internal corrosion of piping welds in the turbine plant cooling water system, and the staff approved the license renewal applicant's proposal to manage this recurring internal corrosion with inspection methods capable of detecting localized internal corrosion (ADAMS Accession No. ML24078A230).

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-023, Andrew N. Mauer (NEI) - XI.M27, "Fire Water System (FWS)," removal of components with license renewal intended functions of leakage boundary or structural integrity as not within program scope.

Overview of Public Comment:

The comment requested that AMP XI.M27, "Fire Water System (FWS)," program element, "Detection of Aging Effects," be revised to delete the following paragraph because management of aging effects is limited to those that could impact performance of the intended functions:

> "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.”

Response:

The staff disagrees with the comment. The staff disagrees with removing the paragraph in AMP XI.M27, Detection of Aging Effects program element, related to fire water system components having leakage boundary (spatial) or structural integrity (attached) intended functions because it states what AMPs, other than AMP XI.M27, the NRC staff finds sufficient to manage the effects of aging for these components. In addition, it clearly states that flow blockage due to fouling does not need to be managed for fire water system components having leakage boundary (spatial) or structural integrity (attached) intended functions.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-024, Andrew N. Mauer (NEI) - XI.M27, “Fire Water System (FWS),” removal of components with license renewal intended functions of leakage boundary or structural integrity as not within program scope.

Overview of Public Comment:

The comment requests that Table XI.M27-1, “Fire Water System Inspection and Testing Recommendations[a, b, c],” in GALL-SLR, Volume 2, Revision 1 be revised to perform internal inspections of sprinkler system piping as a one-time inspection, based on LR-ISG-04, “Aging Management of Fire Protection Systems for License Renewal.” LR-ISG-04 states that oxygen is introduced into the sprinkler system each time the system is opened which accelerates the potential for corrosion, and there is reasonable assurance that unacceptable flow blockage will not occur through the SPEO if inspections following 55 years of plant operation do not identify unacceptable flow blockage. In addition, the comment stated that Table XI.M27-1, “Fire Water System Inspection and Testing Recommendations[a, b, c],” contradicts the guidance in the Detection of Aging Effects program element related to augmented inspections for portions of water-based fire protection system components that have been wetted but are normally dry. Specifically, the guidance states that, “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.”

Response:

The staff disagrees with the comment. LR-ISG-04, “Aging Management of Fire Protection Systems for License Renewal,” recommended baseline pipe wall thickness evaluations of the fire protection piping prior to the end of the current license term, and pipe wall thickness evaluations during PEO to detect general corrosion. It did not eliminate the need to manage general corrosion. However, LR-ISG-2012-02, “Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,” eliminated the alternative of using wall thickness evaluations instead of flow tests or internal visual

examinations for managing flow blockage based on operating experience. Specifically, LR-ISG-2012-02 states, “Flow testing and internal visual inspections are capable of identifying flow blockage because of fouling; however, external wall thickness measurements might not be capable of identifying these impacts when general corrosion might be having a minor effect on wall thickness while generating sufficient corrosion products to cause flow blockage.”

The staff disagrees that the guidance in Table XI.M27-1, “Fire Water System Inspection and Testing Recommendations[a, b, c],” contradicts the guidance in the Detection of Aging Effects program element related to augmented inspections for portions of water-based fire protection system components that have been wetted but are normally dry. The augmented tests and inspections in the Detection of Aging Effects program element are conducted on piping segments that cannot be drained or piping segments that allow water to collect. Augmented tests and inspections are tests and inspections beyond those recommended in Table XI.M27-1. The guidance states “no further augmented tests or inspections are necessary,” it does not state the tests and inspections recommended in Table XI.M27-1 are not necessary.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-026, Andrew N. Mauer (NEI) - XI.M27, “Fire Water System,” removal of reference to flushing in elements 3, 4, and 5, as flushing is performed as a preventive action to mitigate or prevent flow blockage and loss of material by removing foreign material and sediment.

Overview of Public Comment:

The comment requests that flushing be removed from the Parameters Monitored or Inspected, Detection of Aging Effects, and Monitoring and Trending program elements for AMP XI.M27. The comment stated that flushing is preventative action to mitigate or prevent flow blockage and loss of material by removing foreign material and sediment, flushing is not typically relied upon to detect or monitor age-related degradation, and trending flushing results does not provide useful insights to the condition of the Fire Protection system. The comment also noted that data is not collected during flushing activities.

Response:

The staff disagrees with the comment. The staff does agree that flushes mitigate or prevent fouling, which can cause flow blockage or loss of material, by clearing corrosion products and sediment. However, the staff disagrees with removing flushes from the Parameters Monitored or Inspected program element because it states periodic flushes are performed as part of the fire water system program, which is consistent with NFPA 25, 2011 Edition. LR-ISG-2012-2 (ADAMS Accession No. ML13227A361) added the appropriate inspections and tests in NFPA 25 that are related to age-managing applicable aging effects that are associated with loss of material and flow blockage for passive long-lived in-scope components in the fire water system. As noted in LR-ISG-2012-2, degradation in fire protection systems can be detected before a loss of intended function by inspecting and testing the systems in accordance with NFPA 25.

The staff disagrees with removing flushes from the Detection of Aging Effects program element because it is related to the augmented inspections recommended for wetted portions of the fire water system that are normally dry but not configured to drain. Augmented inspections are inspections beyond those recommended in Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations[a, b, c]." The Detection of Aging Effects program element states, "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." A flush is one augmented inspection to confirm these piping segments are clear of corrosion buildup.

The staff disagrees with removing flushes from the Monitoring and Trending program element because a flush can provide valuable insights related to flow blockage and trending flush results can provide insight into projected system performance so that corrective actions may be implemented in a timely manner. The staff notes that at least three prior SLR applicants enhanced their fire water system programs to document, evaluate, and trend deposits, which provides evidence that data can be collected during flushing activities.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-027, Andrew N. Mauer (NEI) - XI.M27, "Fire Water System," Table XI.M27-1, reinstate footnote 6 from GALL-SLR Report, Revision 0, related to functional testing of foam-based fire suppression systems and an option to perform air testing instead.

Overview of Public Comment:

The comment related to a requested that XI.M27, "Fire Water System," Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations[a, b, c]," footnote (6), which relates to the operational test discharge patterns of foam water sprinkler systems, be reinstated in Table XI.M27-1. The comment stated that there is no basis for removing the footnote was provided, and discharging foam for testing purposes is problematic.

Response:

The staff agrees with the comment because footnote (6) was incorrectly removed from GALL-SLR Report, Volume 2, Revision 1, and should be reinstated.

Overview of Proposed Changes:

The staff added new footnote (p) that reinstates the previous footnote related to the operational test discharge patterns of foam water sprinkler systems. In GALL-SLR Report, Volume 2, Revision 1, AMP XI.M27, "Fire Water System," Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations[a, b, c]," added new footnote no. (p) to, "Foam Water Sprinkler Systems," "Operational Test Discharge Patterns," as follows: "Where the nature of the protected property is such that foam cannot be discharged, the nozzles or open sprinklers are inspected for correct orientation and the system tested with air to ensure that the nozzles are not obstructed."

NRC ID: 32-028, Andrew N. Mauer (NEI) - XI.M27, "Fire Water System," revision of the recommendation to perform mainline strainer inspections to consider plant-specific configurations.

Overview of Public Comment:

The comment recommends in Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations[a, b, c]," of AMP XI.M27 to inspect and clean the mainline strainers annually and after each significant flow be revised to consider plant-specific configurations. The comment specifically discussed plant-specific configurations where the mainline strainers installed directly downstream of the fire pump discharge or along the header in a location that experiences flow during each fire pump run or system test. The comment stated that potential blockage would be detected through pump runs, flushes, and flow testing.

Response:

The staff disagrees with the comment. AMP XI.M27 recommends inspections and tests in NFPA 25 that are related to age-managing applicable aging effects that are associated with loss of material and flow blockage for passive long-lived in-scope components in the fire water system. As noted in LR-ISG-2012-2 (ADAMS Accession No. ML13227A361), degradation in fire protection systems can be detected before a loss of intended function by inspecting and testing the systems in accordance with NFPA 25.

Section 7.2.2.3 of NFPA 25 requires mainline strainers be inspected and cleaned after each significant flow (NFPA 25 Section 7.2.2.3 and NFPA 25 Appendix A.7.2.2.3 provide additional information regarding significant flow), and removed and inspected annually for failing, damaged, and corroded parts. Since mainline strainers of the private fire service main may become blocked, damaged, or corrode over time, which could impact their ability to perform their intended function, and since NFPA 25 requires inspections related to age-managing applicable aging effects associated with loss of material and flow blockage, it is appropriate for AMP XI.M27 to include a recommendation to inspect the mainline strainers of the private fire service main. In addition, there has been operating experience where strainers in the normal flow path have been blocked and thus prevented adequate flow.

With regards to plant-specific configurations and testing regimes, applicants have the option to propose using a different approach for managing flow blockage and loss of material of the mainline strainers of the private service main by taking an exception to the AMP and providing a technical justification for the staff to evaluate.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-029, 32-030, Andrew N. Mauer (NEI) - XI.M27, "Fire Water Systems," elimination of recommendations to perform fire protection pump suction strainer and intake screen inspections, as these inspection are not feasible or unnecessary.

Overview of Public Comment:

Comment 32-029 requested that Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations[(a, b, c)]," in AMP XI.M27 be revised to eliminate the recommendation to perform fire pump suction strainer inspections annually and after system actuation because inspections are not feasible and are unnecessary. Specifically, the comment stated that fouling and blockage are not age-related degradation and fire pumps are frequently tested.

Comment 32-030 requested that Table XI.M27-1 in AMP XI.M27 be revised to eliminate the recommendation to perform fire pump intake screen inspections because fouling and blockage are not age-related degradation, and the inspections are unnecessary where intake screens are located behind circulation water traveling screens.

Response:

The staff agrees, in part, and disagrees, in part, with Comments 32-029 and 32-030. AMP XI.M27 recommends inspections and tests in the 2011 Edition of NFPA 25 that are related to age-managing applicable aging effects that are associated with loss of material and flow blockage for passive, long-lived in-scope components in the fire protection system. As noted in LR-ISG-2012-2 (ML13227A361), degradation in fire protection systems can be detected before a loss of intended function by inspecting and testing the systems in accordance with NFPA 25.

Fire pump intake suction screens have a filtration intended function which is associated with two aging effects: flow blockage and loss of material. The 2011 Edition of NFPA 25 Section 8.3.3.7 requires fire pump intake suction screens to be inspected and cleared of debris or obstructions after the waterflow portions of the annual test or after system activations. Although the inspections prescribed by NFPA 25 Section 8.3.3.7 are for clearing the fire pump intake suction screens of any debris or obstructions, these periodic inspections could reasonably be expected to identify loss of material leading to a loss of intended function of the fire pump intake suction screens. Therefore, new footnote (i) will be revised to note that fire pump intake suction screen inspections are for flow blockage and loss of material. Because the fire pump intake suction screens may become blocked, damaged, or corrode over time, which could impact their ability to perform their intended function, and since NFPA 25 includes inspection of fire pump intake suction screens, it is appropriate for AMP XI.M27 to include a recommendation to inspect (loss of material) and clear of debris or obstructions (flow blockage) the fire pump intake suction screens.

In addition to the fire pump intake suction screens, a fire pump suction strainer may be present on the pump bowl. For example, the Wet Pit Suction Screen Installation shown in Figure A.8.2.2 in Annex A of the 2011 Edition of NFPA 25 includes a fire pump suction strainer on the pump bowl. Like fire pump intake suction screens, fire pump suction strainers are passive, long-lived in-scope components in the fire protection system having a filtration intended function associated with the aging effects of flow blockage and loss of material. Because the fire pump suction strainers may become blocked, damaged, or corrode over time, which could impact their ability to perform their intended function, it is appropriate for AMP XI.M27 to include a recommendation to manage loss of material and flow blockage of the fire pump suction strainers. Therefore, new footnote (i) will be revised to note that the fire pump intake suction

screen inspections for flow blockage and loss of material include the fire pump suction strainer when present.

Recognizing that fire pump suction strainer inspections require divers and site's regularly test fire pumps, performing the fire pump suction strainer inspections annually and after each actuation may be excessive and unnecessary. Therefore, the staff agrees that the inspection frequency could be extended if a site has no operating experience related to flow blockage and loss of material of the fire pump suction strainer, and either the site monitors the differential pressure across the fire pump suction strainer or the site monitors the upstream fire pump intake suction screens and/or upstream traveling water screens, if present, to ensure their capability to prevent pass-through of debris that could reach the fire pump suction strainer. Past examination results (no plant-specific operating experience related to flow blockage or loss of material) for the fire pump suction strainer should predict future performance, monitoring differential pressure across the fire pump suction strainer should identify flow blockage, and upstream fire pump intake suction screens and/ or upstream traveling water screens, if present, that are monitored to ensure their ability to prevent pass-through of debris should limit the debris that could buildup on the fire pump suction strainer. Inspections performed every 10 years would verify flow blockage of the fire pump suction strainer is being adequately managed and the suction strainer is not damaged or corroding.

Overview of Proposed Changes:

New footnote (i) to Table XI.M27-1 is revised to note the fire pump intake suction screen inspections are for flow blockage and loss of material associated with the filtration intended function, and to note that inspections include the fire pump suction strainer when present. New footnote (i) is also revised to note that the fire pump suction strainer inspections may be performed every 10 years in lieu of annually and after each system actuation if there is no site-specific operating experience related to flow blockage and loss of material of the fire pump suction strainer and either the differential pressure across the fire pump suction strainer is monitored or activities are conducted to verify the capability of the upstream fire pump suction screens and/or upstream traveling water screens, if present, to prevent pass-through of debris which could reach the fire pump suction strainer. In addition, the footnote is revised to note that the application should describe the activities to verify the capability of the upstream fire pump suction screens and/or upstream traveling water screens, if present.

NRC ID: 32-031, Andrew N. Mauer (NEI) - XI.M27, "Fire Water System," removal of the new footnote "f" to Table XI.M27-1, on sample flow testing of hose stations.

Overview of Public Comment:

The comment requests that new footnote "f" to Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations[(a, b, c)]," related to hose station flow testing be removed because the fire protection systems at nuclear plants are single zone systems and, therefore, the sample-based approach does not apply.

Response:

The staff disagrees with Comment 32-031. AMP XI.M27 recommends inspections and tests in the 2011 Edition of NFPA 25 that are related to age-managing applicable aging effects that are associated with loss of material and flow blockage for passive long-lived in-scope components

in the fire water system. As noted in LR-ISG-2012-2 (ADAMS Accession No. ML13227A361), degradation in fire protection systems can be detected before a loss of intended function by inspecting and testing the systems in accordance with the 2011 Edition of NFPA 25. Section 6.3.1.1 of the 2011 Edition of NFPA 25 requires flow testing at the hydraulically most remote hose connections of each zone of an automatic standpipe system every 5 years. Nuclear power plant buildings (e.g., Reactor Building, Control Building, Turbine Building) have a basement and multiple floors and, therefore, may have multiple automatic standpipe system zones. The Fire Water System design in nuclear power plants varies and single zone standpipe system may not apply to all nuclear power plants. The staff notes that if a specific nuclear power plant has a single zone automatic standpipe system, then the "each zone" requirement in Section 6.3.1.1 of the 2011 Edition of NFPA 25 would not apply to that specific nuclear power plant.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-032, Andrew N. Mauer (NEI) - XI.M27, "Fire Water System," inclusion of language to acknowledge alternative methods of verifying fire water system intended functions beyond those in generic NFPA Code.

Overview of Public Comment:

The comment requests that language be included in AMP XI.M27 that acknowledges alternative methods to NFPA 25 for verifying the fire water system intended functions. The comment stated that NFPA 25 is written for commercial structures and not specifically for nuclear plants, and certain NFPA 25 testing is problematic for nuclear plants.

Response:

The staff disagrees with the comment. Based on OE and for consistency with industry standards, LR-ISG-2012-2 (ADAMS Accession No. ML13227A361) added the appropriate inspections and tests in NFPA 25 that are related to age-managing applicable aging effects that are associated with loss of material and flow blockage for passive long-lived in-scope components in the fire water system. As noted in LR-ISG-2012-2, degradation in fire protection systems can be detected before a loss of intended function by inspecting and testing the systems in accordance with NFPA 25. The staff notes that applicants have the option to propose alternative methods for verifying the fire water system intended functions by taking an exception to the AMP and providing a technical justification for the staff to evaluate.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-033, Andrew N. Mauer (NEI) - XI.M27, "Fire Water System," clarification of the Program Description that dry sprinklers, fast response sprinklers, and standard sprinklers each have different testing or replacement frequencies in NFPA 25.

Overview of Public Comment:

The comment requested clarification on the sprinkler testing or replacement frequencies in the Program Description of AMP XI.M27 because it is confusing and could be misinterpreted because different types of sprinklers have different testing or replacement frequencies per NFPA 25. The comment also indicated that sprinklers subject to time-based replacement is not subject to an aging management review (AMR) per 10 CFR 54.21(a)(1)(ii).

Response:

The staff agrees in part.

The staff agrees with the comment in that the statement in the Program Description of AMP XI.M27 could be misinterpreted. Section 5.3.1 of the 2011 Edition of NFPA 25 (NFPA 25) contains the requirements for replacing or testing sprinklers. Therefore, the Program Description of AMP XI.M27 will be revised to simply refer to Section 5.3.1 which includes sub-sections related to standard, fast response, and dry sprinklers. Information regarding fast response and dry sprinklers was added because they may also exist in nuclear power plants, and AMP XI.M27 in Revision 0 of NUREG-2191, Volume 2 only refers to standard sprinklers.

The staff disagrees with the comment in that sprinklers subject to time-based replacement is not subject to an AMR per 10 CFR 54.21(a)(1)(ii). As indicated in Table 2.1-6, "Typical Structures, Components, and Commodity Groups, and 10 CFR 54.21(a)(1)(i) Determinations for Integrated Plant assessment," in Revision 1 of NUREG-2192, sprinkler heads meet 10 CFR 54.21(a)(1)(i) and are therefore subject to an AMR. Section 5.3.1 of NFPA 25 includes an option for replacement, however, sprinklers, whether replaced or tested, are still subject to annual visual inspection in accordance with Section 5.2.1.1 of NFPA 25 to look for conditions (e.g., leakage, corrosion, incorrect position) that can impact the sprinkler's ability to perform its intended function. In addition, water spray systems are subject to annual operational testing during which spray patterns are checked to identify blockage. For sprinklers and the water spray system, both the visual inspection and operational testing are recommended in Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations[a, b, c]," in Revision 1 of NUREG-2191, Volume 2. In addition, there is operating experience related to sprinklers (e.g., leaking, blocked).

Overview of Proposed Changes:

Revise the Program Description of AMP XI.M27 to refer to Section 5.3.1 of NFPA 25 which includes the requirements for replacing or testing sprinklers which includes sub-sections for standard, fast response, and dry sprinklers.

Associated technical basis for the Program Description changes are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," section X.M27, "Fire Water System."

NRC ID: 32-034, Andrew N. Mauer (NEI) - Editorial comment to review and correct footnote numbering and references for Table XI.M29-1, "Tank Inspection Recommendations" affecting XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," and XI.M30, "Fuel Oil Chemistry."

Overview of Public Comment:

The comment recommends an editorial review and correction as needed of Table XI.M29-1, "Tank Inspection Recommendations[(a, b)]" footnote numbering and references for AMPs XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks" and XI.M30, "Fuel Oil Chemistry."

Response:

The NRC Staff agrees with the comment and did a review of footnote numbering and references related to Table XI.M29-1, within AMPs XI.M29 and XI.M30. In XI.M30, element 4, "Detection of Aging Effects," reference to "Table XI.M29 1, Footnote 1" needs to be changed to "Table XI.M29 1, Footnote a."

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, AMP XI.M30, element 4, "Detection of Aging Effects," reference to "Table XI.M29 1, Footnote 1" is changed to "Table XI.M29 1, Footnote a."

The rest of the footnote numbering and references related to Table XI.M29-1, "Tank Inspection Recommendations[(a, b)]" within AMPs XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks" and XI.M30, "Fuel Oil Chemistry," are correct.

NRC ID: 32-035, Andrew N. Mauer (NEI) - XI.M32, "One-Time Inspection," Revision of Program Description and Table XI 01 to eliminate subjective guidance for inspections, for phrases "just prior" to "ten years prior."

Overview of Public Comment:

The comment recommends for XI.M32, "One-Time Inspection," revising the first sentence of the Program Description, for the phrases "just prior" to "ten years prior" to eliminate subjective language.

Response:

The staff agrees with the comment. The first sentence of the XI.M32 "One-Time Inspection" Program Description and Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs of the GALL-SLR, Revision 1," will be revised to more clearly reflect the inspection timing requirements.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, XI.M32 "One-Time Inspection" Program Description is revised to state:

> A one-time inspection of selected components is conducted 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the beginning of a subsequent period of extended operation (e.g., prior to the second period of extended operation).

In GALL-SLR Report, Volume 2, Revision 1, Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs of the GALL-SLR, Revision 1," Section XI.M32, Implementation Schedule is revised to state:

> 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. Structures and components should be inspected only after an incubation period of sufficient 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.

Associated technical basis for the XI.M32, Program Description, change is included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," under Section XI.M32 and Table XI-01.

NRC ID: 32-037, Andrew N. Mauer (NEI) - XI.M32, "One-Time Inspection," Addition of heat transfer testing as an inspection method option for reduction of heat transfer due to fouling.

Overview of Public Comment:

The comment recommends for XI.M32, "One-Time Inspection," adding heat transfer testing as an inspection method option for managing reduction of heat transfer due to fouling of in-scope components, since heat transfer testing is a viable, nonintrusive testing method that provides reasonable assurance that intended functions are maintained. Further, this technique reduces unavailability of plant equipment.

Response:

Staff disagrees with the comment. Heat transfer testing is a testing method commonly performed in aging management programs using periodic testing (such as the Open-Cycle Cooling Water AMP), since fouling of heat exchangers is a phenomenon that happens over time due to normal use. Consequently, making the requested change to the One-Time Inspection AMP would result in an available testing option that would likely never be used. If an applicant needed to perform heat transfer testing of a heat exchanger on a one-time basis, Table XI.M32-1 of the GALL-SLR Report, Revision 1, contains a note (a) that allows applicants to use alternative testing methods to those recommended in Table XI.M32-1 by taking an exception and providing a technical justification.

Overview of Proposed Changes:

Not Applicable.

NRC ID: 32-038, Andrew N. Mauer (NEI) - XI.M32, "One-Time Inspection," Addition of lubricating oil sampling for corrosion products as an inspection method for loss of material for components in lubricating oil environment.

Overview of Public Comment:

The comment recommends for XI.M32, "One-Time Inspection," adding sampling for corrosion products as an inspection method for loss of material for components in a lubricating oil environment, since sampling provides a nonintrusive testing method capable of detecting degradation in the system and allows for samples to be taken during normal plant operation and eliminates additional unavailability and the associated increase to plant risk.

Response:

See the response to Comments 3, 11, 12, and 17, which removed the recommended one-time inspection of the Lubricating Oil Analysis AMP; therefore, this comment is no longer applicable.

However, as noted in the first paragraph of the Program Description on page XI-211 of the GALL-SLR Report, Revision 1, the one-time inspection is focused on 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. Because the inspections are focused on locations isolated from the flow stream, sampling a lube oil system for corrosion products (which relies on the flow stream to transport the corrosion products throughout the system) would not be an effective means for analyzing locations isolated from the flow stream.

Overview of Proposed Changes:

Not Applicable.

NRC ID: 32-039, Andrew N. Mauer (NEI) - XI.M32, "One-Time Inspection," addition of lubricating oil sampling for corrosion products as an inspection method for loss of material for components in lubricating oil environment.

Overview of Public Comment:

The comment recommends for XI.M32, "One-Time Inspection," including stainless steel as part of the steel sample population. Detection of Aging Effects states, "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." Steel is the bounding material managed by XI.M32 and, as such, if degradation is not occurring in steel, then there is reasonable assurance that no degradation is occurring in stainless steel exposed to the same service environment.

Response:

The staff disagrees with this comment. Due to the highly varied nature of the method by which stainless steel is typically protected from corrosion (i.e., oxide layer passivation), steel (i.e., carbon steel) cannot be claimed as a bounding material for stainless steel when the passivation layer is disrupted. The initiation of localized corrosion (pit or crevice) can lead to uniquely rapid penetration in stainless steel, in part driven by the presence of an isolated anodic region that is surrounded by a relatively large cathodic surface. In addition, the general thinning corrosion to which carbon steel is highly susceptible and to which stainless steel is generally so resistant, is easily contrasted with stress corrosion cracking, to which stainless steel is susceptible and to which carbon steel is very resistant.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-040, Andrew N. Mauer (NEI) - XI.M32, "One-Time Inspection," removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.

Overview of Public Comment:

The comment requests removal of prescriptive corrective action recommendations from XI.M32, "One-Time Inspection," since the appropriate corrective actions are highly dependent on the specific details of the issue. In Element 7, the 2nd paragraph recommends sample expansion, but the 3rd paragraph recommends implementation of a periodic program.

Response:

The staff agrees in part. The staff disagrees with removal of the prescriptive corrective action recommendations but agrees that clarification is needed to Element 7 of the One-Time Inspection AMP. Because the initial inspection is taking place within the one-time inspection program, that means degradation that could prevent the component from meeting its intended function is not expected; therefore, when degradation is found, scope expansion needs to occur. The staff will clarify the reason for two possible actions in response to inspection findings that don't meeting the acceptance criteria.

Overview of Proposed Changes:

Staff clarified that for any inspection (original or expanded scope) that does not meet acceptance criteria, if the cause of degradation is found to be systemic, periodic inspections will commence. If degradation is found to be from an assignable non-systemic cause, periodic inspections will not be required.

In GALL-SLR Report, Volume 2, Revision 1, XI.M32, "One-Time Inspection," Element 7, "Corrective Actions," the last paragraph is revised to include the following:

> 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. However, if the aging effect can

be shown to be from an assignable non-systemic cause, alternative options (e.g., an additional one-time inspection performed after replacement of a component found to be non-compatible with the system and environment combination) can be implemented.

In SRP-SLR, Revision 1, Section A.1.2.3.7, "Corrective Actions" is revised as follows:

For one-time based programs, when an aging effect identified during an inspection does not meet acceptance criteria or projected results of the inspections of a material, environment, and aging effect combination does not meet acceptance criteria; a periodic inspection program is developed for the specific combination(s) of material, environment, and aging effect. However, if the aging effect can be shown to be from an assignable non systemic cause, alternative options (e.g., an additional one-time inspection performed after replacement of a component found to be non-compatible with the system and environment combination) can be implemented.

Associated technical basis for the XI.M32 Corrective Actions changes are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," under section XI.M32. Associated technical basis for the SRP Section A.1.2.3.7 change is included in Table 3-17, "SRP-SLR, Revision 1, Appendices A.1, A.2, A.3, and A.4, Differences from SRP-SLR, Revision 0, and Their Technical Bases."

NRC ID: 32-041, Andrew N. Mauer (NEI) - XI.M33, "Selective Leaching," removal of opportunistic inspections whenever components are made accessible.

Overview of Public Comment:

The comment recommends removal of opportunistic inspections whenever components are made accessible from the XI.M33 guidance.

Response:

The staff disagrees with this comment. As documented in NUREG-2222, "Disposition of Public Comments on the Draft Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG–2192," part of the basis for reducing the extent of inspections for selective leaching during the subsequent period of extended operation (i.e., 3 percent with a maximum of 10 components per GALL-SLR guidance) when compared to the extent of inspections for selective leaching during the initial period of extended operation (i.e., 20 percent with a maximum of 25 components per GALL Report, Revision 2 guidance) was that "[o]pportunistic inspections will be conducted throughout the period of extended operation whenever components are opened, buried, or submerged surfaces are exposed…"

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-042, Andrew N. Mauer (NEI) - XI.M33, "Selective Leaching," Include hardness testing as an available option for performing inspections.

Overview of Public Comment:

The comment recommends inclusion of hardness testing as an available option for performing inspections for selective leaching with acceptance criteria that remains the same as previously contained in NUREG-1801, Revision 2.

Response:

The staff does not agree with this comment. The technical basis for removing hardness testing is documented in the Technical Bases Document (initial report)Revision, "Technical Bases for Changes in the Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG–2192." In addition, the staff's observations (shown below) documented in its audit report related to the NEI proposed revision to GALL-SLR Report AMP XI.M33, "Selective Leaching" (ADAMS Accession No. ML22353A608) further supports not re-introducing hardness testing to the AMP at this time. Applicants have the option to propose using hardness testing by taking an exception to the AMP and providing a technical justification for the staff to evaluate.

> "Hardness testing can theoretically identify the presence of selective leaching. However, the Selective Leaching State-of-the-Art report notes for field measurements, parameters such as surface preparation and the orientation of the indenter may affect the measurement and introduce uncertainty. The report states that further work to understand the reliability and essential parameters of field hardness testing as a means to identify selective leaching may be warranted."

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-043, Andrew N. Mauer (NEI) - XI.M33, "Selective Leaching," rephrase Element 4 to present the information in a simple structure, similar to AMP XI.M41.

Overview of Public Comment:

The comment recommends rephrasing XI.M33, "Selective Leaching," Element 4 to present the information in a simple structure, similar to AMP XI.M41; breaking the contents of the element into shorter paragraphs, bullets, tables for inspection quantities by time period, and footnotes to the table. The recommendation would be to structure Element 4 similar to the proposed mark-up of XI.M33 previously submitted to the NRC by NEI in its letter dated January 12, 2022 (ADAMS Accession No. ML22019A292). The intent of this change is editorial in nature to simply improve readability.

Response:

The staff does not agree with this comment. The inspection quantities in GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," are provided in a tabular format because they vary based on material, environment, and preventive action category. This is not

the same as GALL-SLR Report AMP XI.M33, “Selective Leaching,” where the inspection quantities are consistent across different material and environment combinations (i.e., 3 percent with a maximum of 10 components).

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-046, 32-047, 32-048, 32-049, 32-115, Andrew N. Mauer (NEI) - XI.M33, “Selective Leaching,” removal of the increased sample size for buried gray cast iron components and related topics.

Overview of Public Comment:

The comment recommends removing the increased sample size for selective leaching inspections of buried gray cast iron components.

Response:

NEI GALL-SLR Comments 32-046, 32-047, 32-048, 32-049, and 32-115 (Technical Basis #5) relate to removing the increased sample size for selective leaching inspections of buried gray cast iron components. The staff agrees with these comments, in part. The staff agrees that the increased sample size (i.e., 20 percent of the population with a maximum of 25 components) is overburdensome in most cases; however, the staff has determined that it is reasonable for applicants to provide a technical justification when using the reduced sample size specified in GALL-SLR Report AMP XI.M33 (i.e., 3 percent of the population or a maximum of 10 components) for this specific material and environment combination based on reasons already outlined in the Technical Bases Document, Supplement 1. In addition, this approach is consistent with recent subsequent license renewal applicants who have used results of selective leaching inspections, lack of adverse operating experience, condition and robustness of external coatings, and demonstration of non-corrosive soil to justify the reduced sample size specified in GALL-SLR Report AMP XI.M33 for this material and environment combination (see the Safety Evaluation Related to the Subsequent License Renewal of St. Lucie Plant, Units 1 and 2 (ADAMS Accession No. ML23219A003) and the Safety Evaluation Related to the Subsequent License Renewal of Point Beach Nuclear Plant, Units 1 and 2 (ADAMS Accession No. ML22140A127) for examples). The staff notes, however, that 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 when technical justification is not submitted. Staff responses to other insights brought up by the commenter are addressed below.

In comments 32-046, 32-048, and 32-115, the commenter stated that a new further evaluation section should be created. The staff considered incorporating this recommendation; however, the staff’s revised approach of requesting a technical justification within the AMP is consistent with language in other AMPs such as XI.M41, “Buried and Underground Piping and Tanks” (e.g., applicants provide justification when cathodic protection is not provided).

In comments 32-046 and 32-115 the commenter states this revised guidance is apparently driven by a single event in NRC Information Notice 2020-04, “Operating Experience Related to Failure of Buried Fire Protection Main Yard Piping.” NRC Information Notice 2020-04 was not

intended to be an exhaustive list and the staff is aware of other instances of significant external surface selective leaching of buried gray cast iron piping.

In comment 32-046 the commenter brings up various risk aspects, stating in part that this revision is based on an event which resulted in the loss of functionality of the fire protection system for only 18 minutes which is negligible with respect to fire risk. The staff notes that allowing age related degradation to progress to the point of loss of functionality of the fire protection system is not an effective aging management strategy.

In comment 32-047 the commenter states if the NRC elects not to remove the new recommended increased sample size for buried gray cast iron, then the guidance should be revised to recommend a sample size for the entire station rather than on a per unit basis. Since the staff removed the increased sample size (provided a technical justification is submitted), this comment is no longer applicable.

In comment 32-049 the commenter states (a) clarify the new bullet point recommending the increased sample size for buried gray cast iron and state that mechanical inspections of buried cast iron components are not required if the coating is intact; (b) removal of an intact coating to perform mechanical testing will introduce a vulnerability at the field applied coating repair. Since the staff removed the increased sample size (provided a technical justification is submitted), this comment is no longer applicable. In addition, the staff notes that AMP XI.M33 does not recommend removal of intact coatings.

Overview of Proposed Changes:

Based on the comments, the staff revised GALL-SLR Report, Volume 2, Revision 1, AMP XI.M33 “detection of aging effects” program element as follows:

- 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. A technical justification is submitted with the SLRA when using this sample size for gray cast iron piping exposed to soil (e.g., based on results from inspections previously conducted, lack of adverse operating experience, demonstration of non-corrosive soil, condition and robustness of external coatings).
- 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 when technical justification is not submitted.

NRC ID: 32-050, Andrew N. Mauer (NEI) - XI.M33, “Selective Leaching,” tabulation of Element 6.

Overview of Public Comment:

The comment recommends tabulation of Element 6 to be structured like the proposed mark-up of XI.M33 previously submitted to the NRC by NEI in its letter dated January 12, 2022 (ADAMS Accession No. ML22019A292). The intent of this recommendation is to improve readability.

Response:

The staff does not agree with this comment. The acceptance criteria program element of GALL-SLR Report, AMP XI.M33, “Selective Leaching,” is clear and concise as written. Converting this paragraph to a tabular format is not warranted. In addition, the NEI proposed mark-up of XI.M33 makes substantive, technical changes to the GALL-SLR Report AMP XI.M33 including added acceptance criteria for hardness testing and for demonstrated NDE techniques. The staff evaluation of the NEI proposals on hardness testing and demonstrated NDE techniques can be found in the staff responses to 32-042 and 32-053.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-051, Andrew N. Mauer (NEI) - XI.M33, “Selective Leaching,” removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.

Overview of Public Comment:

The comment recommends the following related to AMP XI.M33, “Selective Leaching:”

- Remove prescriptive corrective actions (PCAs) recommendations for additional inspections to be performed when acceptance criteria are not met.
- Project selective leaching through the next scheduled inspection rather than through the end of the subsequent period of extended operation (SPEO).
- Eliminate overly conservative acceptance criteria including absence of a surface layer that can be easily removed from cast iron components and a change in color for copper-alloy components.

Response:

- The staff disagrees with the comment. The response related to removing PCAs is addressed in the staff’s response to comment 13.
- The commenter notes that projection of wall loss through the end of the SPEO is unwarranted and contrary to guidance used in other AMPs where degradation is projected to the next inspection. However, the staff notes that although other AMPs may project degradation to the next inspection, they typically require a much larger sample size (typically 20 percent with a maximum of 25 components) when compared to the sample sizes in AMP XI.M33.
- The staff does not agree with removing the absence of a surface layer that can be easily removed from cast iron components as an Element 6 acceptance criterion for detecting selective leaching of cast iron components. An easily removable surface layer that does not otherwise appear as a corrosion product layer (e.g., rust) is textbook evidence of selective leaching.
- The staff does not agree with removing the presence of green copper oxide as an Element 6 acceptance criterion for detecting selective leaching of copper alloys. As noted in the

Technical Bases Document (Initial Report), green copper oxide was added based on staff field observations of dealloying in aluminum bronze components.

- The staff notes that for components not meeting Element 6 acceptance criteria 1-3, a corrective action would most likely be performed. If subsequent inspections are performed (minimum of five inspections or 20 percent of the population when 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), and Element 6 acceptance criteria 1-3 are then met, Element 6 acceptance criteria 4 would still need to be met. Therefore, acceptance criteria 1, 2, 3, and 4 are all essential elements of the XI.M33 AMP.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-052, Andrew N. Mauer (NEI) - XI.M33, "Selective Leaching," If prescriptive corrective action guidance remains, sample expansion inspections for unacceptable results of inspections performed in the latter half of the 10-year inspection interval be performed within the first 4 years of the next 10-year inspection interval.

Overview of Public Comment:

The comment recommends the following related to AMP XI.M33, "Selective Leaching:"

- The final sentence in Element 6 should refer to criterion 4 rather than criterion 3.
- Expanded sample inspections for unacceptable inspections performed in the latter half of the 10-year inspection interval should be performed within the first 4 years of the subsequent inspection interval.

Response:

NRC staff agrees with this comment. For Element 6 "Acceptance Criteria" of AMP XI.M33, NRC staff revised guidance such that no credit be used for the material properties of the dealloyed portion of the component when evaluating a component in relation to "criterion (4)" rather than "criterion (3)."

- For expanded sample inspections required by Element 7 "Corrective Actions" of AMP XI.M33 and identified during the latter half of the current inspection interval, NRC staff revised guidance that the additional inspections be performed "within 4 years after the end of the 10-year interval" rather than "within the next refueling outage interval."

Overview of Proposed Changes:

In the GALL-SLR Report, Volume 2, Revision 1, XI.M33, Program Element 6, "Acceptance Criteria," last sentence, "criterion (3)" is changed to "criterion (4)."

In XI.M33, Program Element 7, "Corrective Action," is revised to include, "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 4 years after the end of the 10-year interval."

Associated technical basis for the Acceptance Criteria and Corrective Action change are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," X.M33, "Selective Leaching."

NRC ID: 32-055, Andrew N. Mauer (NEI) - XI.M41, "Buried and Underground Piping and Tanks," elimination or clarification of the coating recommendation for buried cementitious piping.

Overview of Public Comment:

The comment recommends elimination or clarification of the coating recommendation for buried cementitious piping. Element 2, Table XI.M41-1 provides preventive action recommendations including coatings for cementitious piping and references Table 1 of NACE SP0169-2007 or Section 3.4 of NACE RP0285-2002. These NACE documents identify polymeric coatings that are not typically installed on cementitious piping. The internal and external mortar essentially act as a coating for the embedded reinforcement, but this does not align with the NACE standards.

Response:

The staff does not agree with this comment. Before addressing the new recommendation in the comment in GALL-SLR Report Revision 1 to provide external coatings for underground cementitious piping, the staff would like to provide two clarifications:

- GALL-SLR Report AMP XI.M41 manages the aging of the external surfaces of buried piping and does not recommend internal coatings for buried or underground cementitious piping.
- The recommendation to provide external coatings for buried cementitious piping has been in place since the creation of AMP XI.M41 with the issuance of GALL Revision 2 in December 2010. External corrosion protection, beyond relying on the external mortar, may be warranted for buried concrete piping based on environmental conditions (e.g., low pH, high chlorides, high sulfates). Applicants should provide a technical justification when they do not provide external corrosion control (i.e., coatings or cathodic protection) for buried cementitious piping. An example justification and staff's evaluation are provided in Section 3.0.3.2.21, "Buried and Underground Piping and Tanks," of the Safety Evaluation Report Related to the Subsequent License Renewal of Surry Power Station, Units 1 and 2 (ADAMS Accession No. ML20052F523).

The staff noted the following in the technical basis that went out for public comment for the new recommendation in GALL-SLR Report Revision 1 to provide external coatings for underground cementitious piping: (a) external coatings could have helped prevent a recent failure of prestressed concrete cylindrical piping in an underground environment; and (b) barrier coatings are recommended for atmospheric exposure of concrete pressure pipe where the exposed line may be subjected to large temperature fluctuations, wetting and drying cycles, freezing and thawing cycles, and atmospheric carbonation. Although underground cementitious piping may not have been installed with a polymeric external coating as the commenter pointed out, based on the above reasons, applicants should provide technical justification when external coatings are not provided for underground cementitious piping.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-056, Andrew N. Mauer (NEI) - XI.M41, "Buried and Underground Piping and Tanks," clarification of NRC recommendations with respect to cathodic protection.

Overview of Public Comment:

The comment recommends clarification of NRC recommendations with respect to cathodic protection. The GALL-SLR guidance implies that cathodic protection may not be needed for certain stations or buried piping systems but, in practice, the NRC has been highly resistant to any attempts to justify an aging management program that does not rely on cathodic protection for all metallic and cementitious piping.

Response:

The staff does not agree that changes with respect to cathodic protection recommendations are necessary. GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," was created with the issuance of NUREG-1801 (Revision 2) in 2010. In its response to public comment No. 894 in NUREG-1950, "Disposition of Public Comments and Technical Bases for Changes in the License Renewal Guidance Documents NUREG 1801 and NUREG-1800 (ADAMS Accession No. ML11116A062)," the staff stated the following:

> It is the staff's position that preventive actions such as the use of coatings, installation of cathodic protection, and use of appropriate backfill, are an essential part of a comprehensive program for managing the aging of the external surfaces of buried and underground piping and tanks. If, during the aging management review process, an applicant determines that in-scope buried piping and tanks do not conform to the preventive actions described, the staff would expect that the applicant would either commit to take action to establish such preventive actions prior to the period of extended operation or take an exception to the AMP and provide a thorough technical justification for the exception.

The staff considers cathodic protection an essential part of a comprehensive program for managing the aging of the external surfaces of buried piping and does not consider it unreasonable for applicants to provide a thorough technical justification when cathodic protection is not provided.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-057, Andrew N. Mauer (NEI) - XI.M41, "Buried and Underground Piping and Tanks," removal of reference to carbonate/bicarbonate environment.

Overview of Public Comment:

The comment recommends removal of reference to carbonate/bicarbonate environment. Operating experience from the gas pipeline industry indicates that high-pH stress corrosion cracking can occur in a carbonate/bicarbonate environment in piping directly downstream of compressor stations. This degradation mechanism is highly temperature-sensitive and occurs in a relatively narrow cathodic potential range (-600 to -750 mV $Cu/CuSO_4$). The high temperature environment downstream of compressor stations (>150°F) is not likely to be experienced in buried piping at nuclear plants and cathodic protection is maintained outside of the range where this mechanism is known to occur. There is no known OE of this mechanism occurring at a nuclear plant.

Response:

The staff does not agree with this comment. The staff recognized in the Technical Bases Document (initial report), and LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations (ADAMS Accession No. ML15125A377)," that cracking of buried steel piping would only occur under specific conditions (see below). These conditions may be unlikely at a nuclear plant; however, they could still occur. The fact that this aging effect/mechanism only occurs under specific conditions and that those conditions are unlikely is not an adequate technical basis for removing it from the GALL-SLR Report, Technical Bases Document (initial report), and LR-ISG-2015-01 stated:

> Technical Bases Document (initial report): "[p]otential cracking of steel materials was addressed in LR ISG 2015-01, "Changes to Buried and Underground Piping and Tank Recommendations." The term, "steel in carbonate/bicarbonate environment only" was added to clarify that cracking of steel components would only occur in these two environments. The staff concluded this based on a review of National Association of Corrosion Engineers (NACE) SP0169-2013, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," Figure 2, "SCC Range of Pipe Steel in Carbonate/Bicarbonate Environments.""
>
> LR-ISG-2015-01: "[t]he staff also added a recommendation related to the potential for stress corrosion cracking of steel and stainless steel components. Because this cracking is dependent on plant-specific characteristics (e.g., the cathodic protection polarization level, temperature, pH)…"

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-058, 32-072, Andrew N. Mauer (NEI) - XI.M41, "Buried and Underground Piping and Tanks," clarification of guidance related to aging effects for High Density Polyethylene (HDPE) buried piping.

Overview of Public Comment:

The comment recommends clarification of whether managing the effects of aging for HDPE buried piping in AMP XI.M41, "Buried and Underground Piping and Tanks" is warranted given that new AMP XI.M43, "HDPE and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping," covers the same material and subject matter.

The comment recommends elimination of contradictory statements within XI.M43 and contradictions between the new XI.M43 AMP and the proposed revision to XI.M41. The comment adds that the new proposed AMP XI.M43 only addresses HDPE that meets the requirements of ASME Section III, Mandatory Appendix XXVI. As such, the recommendations do not apply to HDPE installed in non-safety related systems within the scope of License Renewal (e.g., Fire Protection System). However, Element 4, paragraph (a) of XI.M43 refers to vendor/manufacturer inspection recommendations for situations where 10 CFR 50.55(a) and/or NRC approved alternatives do not apply, which are non-safety related applications. Further, the exceptions to the Table XI.M43-2 (now re-named to XI.M43-3) inspection quantities presented in Element 4, paragraph (b)(ii) refer to non-safety-related piping (i.e., not subject to ASME Section III requirements). The proposed revision to AMP XI.M41 states that buried HDPE piping is no longer managed by the Buried and Underground Piping and Tanks AMP. Non-safety-related buried HDPE piping is not addressed by any AMP in draft Revision 1 of GALL-SLR.

Response:

The staff disagrees with the commenter that there are contradictory statements within and between AMP XI.M43 and the proposed revision to AMP XI.M41. The staff also disagree that AMP XI.M41 and AMP XI.M43 are managing the same materials.

On the other hand, the staff agrees with the commenter about the following: (1) AMP XI.M43 Program Description and/or Scope of Program did not specifically state that the aging of both safety-related and in-scope non-safety related HDPE and CFRP-repaired piping are managed by AMP XI.M43, (2) AMP XI.M43 Program Description and/or Scope of Program did not provide a clear definition for in-scope non-safety-related HDPE piping when referenced in AMP, (3) AMP XI.M43 Program Description and/or Scope of Program did not specifically state that a reference to CFRP-repaired piping is meant only for the installation or application of the CFRP repair on the interior surface of a pipe as a structural liner, and (4) AMP XI.M43 Parameters Monitored or Inspected did not provide clear guidance on what requirements are followed when conducting the inspection of in-scope non-safety-related HDPE and CFRP-repaired piping. To address this comment, the staff revised AMP XI.M43 Program Description, Scope of Program, and Parameters Monitored or Inspected for clarification.

Overview of Proposed Changes:

The staff revised GALL-SLR Report Volume 2, Revision 1, AMP XI.M41, to clarify that the AMP does not manage the effects of aging for HDPE piping and/or CFRP-repaired piping.

In addition, for clarity, the staff revised AMP XI.M43 Program Description to state that AMP XI.M43 is applicable for safety-related and in-scope non-safety-related buried and underground

HDPE piping and CFRP-repaired piping. The CFRP-repaired piping is defined in this AMP as application of CFRP on the internal surface of metal pipe as structural lining. AMP XI.M43 Element 1, “Scope of Program” is revised so that when HDPE is referenced for non-safety-related piping that is in the scope of this AMP, it states that the HDPE should continue to meet the original construction code or fabrication. AMP XI.M43 Parameters Monitored or Inspected paragraphs (a) and (b) are revised that visual inspections of the in-scope non-safety related piping are conducted per the requirements of construction code, or plant procedures. For in-scope non-safety related piping, a system leakage test is performed to detect leakage in accordance with the original construction code, or in accordance with ASME Code, Section XI if no system leakage test is specified in the original construction code.

Associated technical basis for the Program Description and Scope of Program changes are included in the Technical Bases Document, Supplement 1, Table 2-33, “GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” sections XI.M41 and XI.M43.

NRC ID: 32-059, Andrew N. Mauer (NEI) - XI.M41, “Buried and Underground Piping and Tanks,” elimination of the recommended minimum length of piping for inspections.

Overview of Public Comment:

The comment recommends in AMP XI.M41, the elimination of the recommended minimum length of piping for inspections (10 linear feet).

Response:

The staff does not agree with this comment. The inspection quantities listed in GALL-SLR Report Table XI.M41-2, “Inspection of Buried and Underground Piping and Tanks,” are based on inspecting 10 linear feet of piping per inspection. Applicants have the option to propose an alternative sampling methodology by taking an exception to the AMP and providing a technical justification for the staff to evaluate.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-062, Andrew N. Mauer (NEI) - XI.M41, “Buried and Underground Piping and Tanks,” removal of reference to National Association of Corrosion Engineers (NACE) qualifications, as NACE no longer exists as a stand-alone organization.

Overview of Public Comment:

The comment recommends in AMP XI.M41 the removal of reference to NACE qualifications because NACE no longer exists as a stand-alone organization.

Response:

The NRC staff does not agree with the comment as written. Although NACE (National Association of Corrosion Engineers) has been incorporated into AMPP (Association for Materials Protection and Performance) because of an organization restructure, NACE qualifications, such as the Coating Inspector Level 2 or 3 qualification or the Cathodic Protection Specialist CP4 qualification as discussed in AMP XI.M41 Element 6, are still certified by AMPP as NACE qualifications for those inspectors who initially qualified under NACE management.

However, the staff recognizes that current and future qualifications will likely be designated as AMPP qualifications rather than NACE qualifications. Therefore, the staff replaced "NACE" with "NACE or AMPP" in the context of qualifications discussed in AMP XI.M41 Element 6.

Overview of Proposed Changes:

In GALL-SLR Report Volume 2, Revision 1, XI.M41, "Buried and Underground Piping and Tanks," Item 6, "Acceptance Criteria," element a, "or Association for Materials Protection and Performance (AMPP)" is added as appropriate. The NRC staff also added clarifying footnote, "NACE International and the Society for Protective Coatings (SSPC) merged in 2021 and created the Association for Materials Protection and Performance (AMPP)," for consistency with its actions to address a similar comment on XI.M43.

In SRP-SLR Revision 1, Appendix A, Section A.4, "Operating Experience for Aging Management Programs," subsection A.4.2, "Position," "Areas of Further Review," "National Association of Corrosion Engineers [NACE]" is replaced with "Association for Materials Protection and Performance [AMPP]." The NRC staff also added a clarifying footnote "NACE International and the Society for Protective Coatings (SSPC) merged in 2021 and created the Association for Materials Protection and Performance (AMPP)."

Associated technical basis for changes are included in the Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," section XI.M41, "Buried and Underground Piping and Tanks," and in Table 3-17, SRP-SLR, Revision 1, "Appendices A.1, A.2, A.3, and A.4, Differences from SRP-SLR, Revision 0, and Their Technical Bases."

NRC ID: 32-063, Andrew N. Mauer (NEI) - XI.M41, "Buried and Underground Piping and Tanks," changing acceptance criteria for buried piping inspections to be based on projection of wall loss through the next scheduled inspection.

Overview of Public Comment:

The comment recommends, in AMP XI.M41, changing the acceptance criteria for buried piping inspections to be based on projection of wall loss through the next scheduled inspection (10 years). Comment states that projection of wall loss through the end of the period of extended operation (PEO) is unwarranted and contrary to guidance used in other AMPs where degradation is projected to the next inspection.

Response:

The staff does not agree with this comment based on the following reasons:

- The staff added the recommendation that wall thickness be projected to the end of the PEO to AMP XI.M41 (and corresponding FSAR Supplement) with the issuance of LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations." In addition, with the issuance of LR-ISG-2015-01, the staff significantly reduced the number of inspections for Preventive Action Categories E and F. Part of the basis for this reduction was that an expansion of sample size is conducted where degradation in the base material (extrapolated to the end of the period of extended operation) results in a potential challenge to the pressure boundary.
- The commenter notes that projection of wall loss through the end of the PEO is unwarranted and contrary to guidance used in other AMPs where degradation is projected to the next inspection. Although other AMPs may project degradation to the next inspection, they typically require a much larger sample size (typically 20 percent with a maximum of 25 components) when compared to the sample sizes in AMP XI.M41 (potentially only one inspection for certain materials and preventive action categories).
- The commenter discusses using a conservative corrosion rate of 16 mils per year (mpy) for projecting external corrosion of buried piping. The staff agrees that 16 mpy can be overly conservative in many instances; however, the staff notes that AMP XI.M41 does not require the use of this value for projecting loss of material rate. The staff notes that LR ISG 2015 01 discusses the use of electrical resistance corrosion rate probes to measure external loss of material rate.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-064, Andrew N. Mauer (NEI) - XI.M41, "Buried and Underground Piping and Tanks," removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.

Overview of Public Comment:

The comment recommends the following related to GALL-SLR AMP XI.M41:

- Remove prescriptive corrective actions (PCAs) recommendations since the majority of recommended corrective actions are adequately addressed through station corrective action programs.
- Projecting piping degradation through the end of the subsequent period of extended operation (SPEO) is overly conservative.

Response:

NRC staff disagrees for the following reasons:

- Although an applicant's corrective active program is a critical part of addressing inspection results that do not meet acceptance criteria, PCAs can be an appropriate approach to

prevent likely loss of function for an in-scope component. For example, Element 7.c of AMP XI.M41 discusses expansion of scope inspections 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. Loss of pressure boundary function would be a serious outcome of a component that does not meet acceptance criteria, and the use of PCAs provides the necessary assurance that a sufficient number of additional inspections are performed to ensure that pressure boundary integrity will be maintained. Based on the staff's technical and engineering judgement, a plant's station corrective action program, without the supplemental use of PCAs, may not provide the necessary assurance that a sufficient number of additional inspections have been performed.

- The staff's response related to projection of wall loss through the end of the SPEO is addressed above in the staff's response to comment No. 32-063.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-065, Andrew N. Mauer (NEI) - XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," detection of aging effects and sample-based inspection approach.

Overview of Public Comment:

The comment recommends that the detection of aging effects program element in XI.M42 be modified to add a bullet which provides guidance specifically for piping components such as valves, pump casings, and flow elements. The comment further requests that this guidance use a sample-based inspection approach similar to that used for piping in this program element.

Response:

NRC staff partially agrees with the comment. NRC staff agrees that there is a gap in the guidance found in the detection of aging effects program element (program element 4) in XI.M42. Program element 4 provides bulleted guidance for extent of inspections for tanks, heat exchangers, and piping, but not explicitly for piping components. But piping components, which are defined in Table IX-B of GALL-SLR, are clearly stated as in-scope for AMP XI.M42.

However, NRC staff does not believe that separate bulleted guidance for piping components is needed. Rather, piping components can be considered as piping for purposes of extent of inspection guidance for piping systems. That is, the "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" can be taken from the piping, piping components, or combination of piping and piping components within a piping system with a common coating/lining material and environment combination. NRC staff cautions that the statement "focusing on components that are most susceptible to the applicable aging effect" applies and that this must be factored into the decisions on including piping components in the inspection sample.

Overview of Proposed Changes:

GALL-SLR Report, Volume 2, Revision 1, XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” Item 4, “Detection of Aging Effects,” the sentence, “For this program element, piping components can be considered as piping of the same coating/lining material and environment combination,” is added.

Associated technical basis for the detection of aging effect change is included in the Technical Bases Document, Supplement 1, Table 2-33, “GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” section XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks.”

NRC ID: 32-066, Andrew N. Mauer (NEI) - XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” clarification of the definitions in Note (c) Inspection Categories.

Overview of Public Comment:

The comment recommends the NRC staff revise AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” Table XI.M42-1 to clarify the definitions in Note (c) Inspection Categories A and B. In SLR-ISG-2021-02-MECHANICAL Appendix H, the same note explicitly defined Note (c), sub-notes 1 and 2 as Category A and B, respectively.

Response:

The staff agrees that a clarification and correction is required due to an editorial error. Table XI.M42-1 Note (c) is edited to be consistent SLR-ISG-2021-02-MECHANICAL Appendix H, Table XI.M42-1 Note (c), Category A and B. “1” and “2” are changed to “A” and “B” respectively.

Overview of Proposed Changes:

In GALL-SLR Report Volume 2, Version 1, AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” Table XI.M42-1, Note (c) Inspection Categories “1” and “2” are changed to “A” and “B”, respectively.

NRC ID: 32-067, Andrew N. Mauer (NEI) - XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.

Overview of Public Comment:

The comment recommends the NRC staff revise AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," to remove prescriptive corrective actions (PCA).

The commenter's justification for removing PCAs in AMP XI.M42 is as follows:

- Coating delamination is typically due to improper coating system selection or installation and doesn't warrant PCA.
- Erosion of heat exchanger coatings is not an immediate concern, but rather a financial decision that should be left to individual station.
- Follow-up inspections every 2 years causes additional system unavailability with associated risks.
- The recommendation for coatings/linings credited for corrosion protection is unclear.

Response:

NRC staff disagrees for the following reasons:

The generic rationale for keeping PCAs in GALL-SLR Report AMPs is addressed in the staff's response to Comment 18. In addition, AMP XI.M42 specific rationale for keeping PCAs in AMP XI.M42 is as follows:

- Although the NRC staff agrees that coating delamination may often be due to improper coating system selection or installation, the purpose of GALL-SLR Report, AMP XI.M42 is to provide reasonable assurance that such delamination does not "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." As such, the guidance of GALL-SLR Report AMP XI.M42 for internal coatings of in-scope components is valid whether the root cause of delamination is improper selection, improper installation, age related degradation, or some other cause.
- The commenter raises the contention that heat exchanger coating erosion is not an immediate concern affecting functionality, but rather a financial decision considering coating repair versus component replacement. However, from the staff's perspective, coating integrity is a potential safety concern as loose coating debris can cause problems downstream and can even cause system unavailability in extreme cases. The purpose of GALL-SLR Report AMP XI.M42 is to provide reasonable assurance that such erosion does not "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." GALL-SLR Report AMP XI.M42 does not provide guidance on how licensees make financial decisions.
- Follow up inspections every 2 years ensure that intended functions of in-scope components are met, and that degradation of coatings/linings does not 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. Therefore, the safety benefits of follow-up inspections justify the additional system unavailability and associated risks.

- The commenter discusses the recommendation for coatings/linings credited for corrosion protection being unclear. The NRC staff would like to reaffirm that GALL-SLR Report AMP XI.M42, as stated in the “Scope” and “Preventive Actions” sections, allows but does not require that external coatings be credited as being a preventive action based on the coating isolating the external surfaces of a component from the environment. However, if the licensee chooses to take this credit and if base material is either exposed or is beneath a blister, the guidance provided in GALL-SLR Report AMP XI.M42 provides an acceptable method to assure that the minimum wall thickness is met and will be met until the next inspection occurs.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-068, Andrew N. Mauer (NEI) - XI.M43, “HDPE Piping and CFRP Repaired Piping,” deletion of new GALL-SLR AMP XI.M43.

Overview of Public Comment:

The comment recommends deletion of new GALL-SLR Report, Volume 2, Revision 1, AMP XI.M43, “HDPE Piping and CFRP Repaired Piping.” The NRC's aging management guidance is based on generally applicable OE indicating age-related issues requiring management to ensure intended functions are maintained. The NRC cites only a single OE example related to CFRP, and this issue was due to improper quality control during installation. No examples of age-related degradation of HDPE have been cited by the NRC in the proposed XI.M43 AMP. Literature review indicates that instances of HDPE piping failures are due to incompatibility with the service environment, improper fusion of joints, or other design or installation issues, and not due to aging.

The design analysis of CFRP replacement piping installed in accordance with ASME Code Case N-871 includes material adjustment factors to account for age-related degradation and qualify the replacement for a 50-year design service life (N-871 requirements are based on AWWA C305-18). HDPE piping is similarly designed with a qualified service life of 50 years. Additional aging management prior to the end of the design service life is not warranted.

The proposed new XI.M43 AMP could cause a chilling effect and indirectly increase industry leakage and decrease nuclear safety during the SPEOs utilizing this AMP. Superseding minimal ongoing inspection requirements with burdensome and low-value aging management will disincentivize stations from upgrading to these superior materials, thereby disincentivizing risk elimination.

Response:

The staff disagrees with the comment. The new AMP was developed to manage the effects of age-related degradation mechanisms that are applicable to HDPE and CFRP-repaired piping. OE exists on the failure of CFRP-repaired pipe specifically related to loss of material due to delamination and flow blockage at a nuclear plant. As noted in the response to comment 26, Element 10, "Operating Experience," of AMP XI.M43 describes proprietary OE regarding the delamination in a CFRP-repaired pipe obtained from a licensee. The licensee treated the details of the OE event as proprietary, and the staff has determined that the technical information is proprietary consistent with 10 CFR 2.390. HDPE piping is not immune to degradation. The staff used its engineering judgement, knowledge gained from industry experience of the aging effects of related materials, and the information provided through the proprietary OE event to determine that (the aging issues and aging management appropriates for CFRP repaired and HDPE piping) is most effectively addressed with a dedicated AMP.

In terms of CFRP replacement piping installed in accordance with ASME Code Case N-871 and associated design service life, the staff recognizes the rigor with which the CFRP-repaired and HDPE piping have been designed and installed in the field. The staff also acknowledges the commenter's point on disincentivizing stations from upgrading to these superior materials, however, the staff notes that the operating experience for these materials is limited, and an understanding of the effects of material selection, fabrication, design, and installation on aging process is incomplete. The aging issues and aging management approaches for CFRP and HDPE piping were considered to be most effectively addressed with a dedicated AMP.

The commenter stated that "there is limited nuclear OE with these materials, but they have extensive history in other industries. OE for other industries demonstrates that these materials are highly reliable and have minimal aging issues…." The staff finds that the operating condition of the CFRP-repaired and HDPE piping used in nuclear plants may be different from the operating condition of those pipes used in other industries. The Commenter did not provide data to show the operating experience of the CFRP and HDPE piping in other industries. Even if the experience of the CFRP-repaired and HDPE piping in other industries has minimal aging issues, it does not imply that CFRP and HDPE piping will not be degraded in nuclear plants. AMP XI.M43 is to ensure that CFRP-repaired and HDPE piping are not degraded in nuclear plants. If the subject pipes do degrade, the monitoring portions of the AMP will detect such degradation and the licensee can take corrective actions prior to the pipe failure. As new OE becomes publicly available, the staff will identify the new OE.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-069, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," deletion of new GALL-SLR AMP XI.M43.

Overview of Public Comment:

The comment recommends using Time Limited Aging Analysis (TLAA) in place of GALL-SLR AMP XI.M43, "HDPE Piping and CFRP Repaired Piping," for aging management of HDPE and CFRP. This approach has been recently used and accepted by the NRC for HDPE piping. The

NRC recently approved the Callaway Plant's first License Renewal Application, which included a TLAA relying on the qualified 40-year service life for HDPE piping installed as a replacement to original ASME Class 3 buried piping as documented in NUREG-2172, Section 4.7.8. The design analyses for HDPE and CFRP meet the six criteria defining a TLAA:

1) Involve systems, structures, and components within the scope of license renewal, as delineated in § 54.4(a)–Piping requiring aging management must be within the scope of license renewal.

2) Consider the effects of aging–The design analyses for HDPE and CFRP consider the effects of aging through the allowable stress limits in ASME Section III, Mandatory Appendix XXVI and through the material adjustment factors in ASME Code Case N-871, respectively.

3) Involve time-limited assumptions defined by the current operating term, for example, 40 years–Although the design analyses for HDPE and CFRP are not typically defined by the current operating term, these analyses are typically based upon a period of plant operation that extends beyond the current license term but may not extend beyond the term of the renewed license.

4) Were determined to be relevant by the licensee in making a safety determination–The design analyses provide the basis for compliance with station design code requirements (or NRC approved relief request) in accordance with ASME Section III, Mandatory Appendix XXVI and ASME Code Case N-871 for HDPE and CFRP, respectively.

5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in § 54.4(b)–The design analyses provide the basis for compliance with station design code requirements (or NRC approved relief request) and, as such, demonstrate that the replacement piping will be capable of performing its intended functions under design basis conditions.

6) Are contained or incorporated by reference in the CLB–The design analyses for modifications that install HDPE or CFRP are incorporated into the station CLB in that they demonstrate compliance with Code requirements or provide the basis for NRC approved relief requests.

Response:

The staff disagrees with the comment.

The staff notes that the time limited aging analysis (TLAA) as defined in 10 CFR 54.3 are licensee calculations and analysis that meet six criteria. Applicants can submit plant-specific TLAAs, which the staff will review for acceptability and technical adequacy. If the use of a TLAA does not meet one of the criteria, a TLAA cannot be used to manage that topic. The commenter provided examples that HDPE and CRFP can be managed by a TLAA because they meet all six criteria. However, the staff disagrees that they meet all six criteria, because they do not meet criterion 2, on considering the effects of aging. The allowable stress limit in the ASME Code,

Section III and material adjustment factor proposed by the commenter are not related to the aging effect. The allowable stress limit and adjustment factor are used to ensure that the subject pipe is capable of supporting the applied loading. The ASME Code, Section III design criteria assure that the component has sufficient load carrying capability to perform its intended function. The design criteria and aging effects are two separate concepts and are not related.

In addition, the staff notes that 10 CFR 54.21(c)(1)(iii) requires that "[t]he effects of aging on the intended function(s) will be adequately managed for the period of extended operation." However, based on the discussion above, there are no provisions for managing the aging effect of the component. As such, the staff establishes AMP XI.M43 to provide the guidance on how to manage the aging effect of a component. The staff further notes that the structural integrity of a component is assured with a two-prong approach—Design Analysis and Inspection. The design analysis establishes that the component can meet the ASME Code, Section III design criteria. Periodic inspections verify that the analytical evaluation is still met by examining the component for degradation that may affect its ability to perform its function. The TLAA by itself cannot ensure the structural integrity of the CFRP-repaired and HDPE piping without periodic inspections. Therefore, TLAA by itself cannot be used to perform the similar actions as described in AMP XI.M43. Callaway Plant used TLAA "Replacement Class 3 Buried Piping" to justify the design life of its HDPE for an additional 20 years, or more, of operation. The TLAA was not used to replace the aging management program of HDPE. The Callaway Plant used the periodic inspection guidance contained in AMP XI.M41 for their aging management program. At the time, there was no specific guidance for HDPE or CFRP, and AMP XI.M41 was the applicable AMP for aging management of HDPE.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-070, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," for CFRP piping, while a TLAA approach works well for the CFRP itself, potential age-related degradation of the host pipe at the terminal ends would need to be managed.

Overview of Public Comment:

The comment recommends revising AMP XI.M41, "Buried and Underground Piping and Tanks AMP," to include the inspections of the existing metal piping, including the terminal ends for the CFRP piping. For CFRP piping, while a TLAA approach works well for the CFRP itself, potential age-related degradation of the host pipe at the terminal ends would need to be managed. Assuming the CFRP replacement does not encompass the entire run of buried piping (i.e., in-scope piping constructed of the original metallic material remains in place and buried terminal ends exist), the XI.M41 Buried and Underground Piping and Tanks AMP can be revised to recommend inspections of the attached original piping, including the terminal ends for the CFRP piping replacement. These inspections would serve as both representative sample inspections for other buried piping constructed of the same material and as verification of the condition of the terminal ends. These inspections would be appropriate representative samples for the XI.M41 AMP since this piping is adjacent to piping with known degradation (i.e., the attached piping replaced with CFRP is assumed to have known degradation which would be why it was replaced).

Response:

The staff disagrees with the comment. The staff considered including CFRP and HDPE piping in AMP XI.M41. However, the staff determined that if CFRP and HDPE piping were incorporated into AMP XI.M41, it would create confusion in the implementation and regulatory enforcement. The new AMP was developed to manage the effects of age-related degradation mechanisms that are applicable to HDPE- and CFRP-repaired piping. The staff finds that the aging issues and aging management approaches for CFRP-repaired piping and HDPE piping in a separated AMP were considered to be most effectively addressed with a dedicated AMP.

For clarification, the staff established the new AMP XI.M43 to manage the CFRP-repaired piping (i.e., CFRP laminate including metal substrate of CFRP terminal ends where the laminate bonds to metal pipe). The design of CFRP-repaired piping requires the metal substrate of terminal ends always meet the minimum design wall thickness. The method of AMP XI.M41 may be used for quality of backfill, external coatings, and/or cathodic protection of the metal substrate of the CFRP-required piping at terminal ends, but the metal wall thickness at the terminal ends are addressed by AMP XI.M43. Furthermore, the CFRP-repaired piping can encompass the full length/run of a metal pipe or the partial length/run of a metal pipe. For cases where the CFRP-repaired piping encompasses the partial length/run of a metal pipe, the partial length/run of the metal pipe not CFRP-repaired is managed by AMP XI.M41.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-071, 32-075, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," deletion of cathodic protection recommendations for CFRP replacement piping, and deletion of coating inspection of the host pipe as a detection of aging effects recommendation for internally applied CFRP replacement piping.

Overview of Public Comment:

The comment (32-071) recommends the NRC staff edit XI.M43, "HDPE Piping and CFRP Repaired Piping," to delete cathodic protection recommendations for CFRP replacement piping. Cathodic protection of the terminal ends is already adequately addressed by the XI.M41, "Buried and Underground Piping and Tanks." The comment adds that cathodic protection of the rest of the host pipe, besides the terminal ends, is not needed. If a modification that installs CFRP only replaces a portion of an in-scope buried pipeline, then the remaining in-scope original piping, including the terminal ends, would be addressed by AMP XI.M41. Repeating the cathodic protection recommendations in XI.M43 unnecessarily overcomplicates the new proposed AMP. Further, alternatives exist to ensure the integrity of terminal ends for CFRP replacement piping. These alternatives include installation of a collar to increase the thickness of the host pipe at the terminal end and location of the terminal end such that it is not directly exposed to soil (e.g., inside a building or in a vault to allow for ease of inspection and to mitigate potential aging issues).

The comment (32-075) recommends deletion of coating inspection of the host pipe as a detection of aging effects recommendation for internally applied CFRP replacement piping. The CFRP piping addressed by this AMP are full-structural replacements where no credit is taken for

the host pipe. Complete degradation of the host pipe such that backfill could impact the CFRP liner during the 20-year renewed operating term is not credible. Further, given that CFRP is installed to replace degraded original piping, significant degradation of the host pipe coating is expected.

Response:

The staff agrees with the comment that if the CFRP repair is performed on the partial length/run of a metal pipe, the unrepaired partial length/run of the metal pipe should be managed by AMP XI.M41.

The staff agrees with the comment that the method of AMP XI.M41 to be used for quality of backfill, external coatings, and/or cathodic protection of the metal substrate of the CFRP-repaired piping at terminal ends.

The staff agrees with the comment that the metal pipe between CFRP terminal end does not need aging management after repair.

The staff disagrees with the commenter's following statements: (a) delete discussions on backfill, coatings, and cathodic protection from XI.M43, (b) repeating the cathodic protection recommendations in XI.M43 unnecessarily overcomplicates the new proposed AMP, and (c) the complete degradation of the host pipe such that backfill could impact the CFRP liner during the 20-year renewed operating term is not credible.

The staff developed XI.M43 to manage aging of the HDPE and the CFRP-repaired piping. The CFRP-repaired piping is composed of CFRP laminate and metal substrate of CFRP terminal ends where the laminate is bonded to metal for load transfer from CFRP to metal and vice versa. The staff believes that discussing the aging effects of each component of CFRP-repaired piping (i.e., CFRP laminate and metal substrate of CFRP terminal ends) does not complicate the guidance but rather it assures their aging is adequately managed during period of extended operation. Furthermore, complete loss of metal wall thickness due to corrosion and exposure of CFRP laminate between terminal ends to backfill is possible since the aging of the metal pipe between CFRP terminal ends is no longer managed after repair.

The staff revised, XI.M43 "Program Description;" and "Preventive Actions;" Table XI.M43-1, "Preventive Actions for Buried and Underground Piping and Tanks," with associated footnotes, and paragraphs 2(a) and 2(b), "Detection of Aging Effects," "Monitoring and Trending," "Acceptance Criteria," and "Corrective Actions" to address various parts of these two comments.

Overview of Proposed Changes:

GALL-SLR, Volume 2, Revision 1, XI.M43 is revised as follows:

- Program Description is rephrased to clarify the applicability of cathodic protection, backfill, and coating to HDPE piping and CFRP-repaired piping.
- Preventive and mitigative techniques for the HDPE piping and the CFRP-repaired piping between CFRP terminal ends may include the quality of backfill.
- In addition, preventive and mitigative techniques for the metal substrate of the CFRP-repaired piping at the CFRP terminal ends of the CFRP-repaired piping may include the quality of backfill, and corrosion inhibiting external coatings, or cathodic protection. In addition, inspection activities for the metal substrate of the CFRP-repaired piping at CFRP

terminal ends may include electrochemical verification of the effectiveness of cathodic protection, external coatings inspection, and verification of metal substrate wall thickness at the CFRP terminal ends. The method of GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," may be used for quality of backfill, external coatings, and/or cathodic protection of the metal substrate of the CFRP-required piping at terminal ends.

- Preventive Actions, Table XI.M43-1, footnotes (a) and (b) are revised to provide clear description of applicability of cathodic protection and backfills to each material type (i.e., HDPE, CFRP, and metal substrate of CFRP terminal ends). Coatings, C(c), and footnote (c) are added since the exterior of metal substrate of CFRP terminal ends may require coatings as a corrosion protection.
- Preventive Actions is revised to state that the methods in XI.M41 are used for cathodic protection, external coatings, and/or quality of backfill for the metal substrate of CFRP terminal ends.
- Preventive Actions is revised by adding the phrase, "The CFRP between terminal ends of the CFRP-repaired piping may come in contact with backfill when the metal pipe between terminal ends are degraded completely." Detection of Aging Effects guidance in Table XI.M43-2 (now renamed to Table XI.M43-3) with footnotes related to cathodic protection for the metal host pipe between terminal ends are deleted because the metal host pipe between terminal ends is replaced by the CFRP-repaired piping, the design does not consider it as a load carrying component, and no credit is taken for it at all.
- Detection of Aging Effects, Table XI.M43-3, originally Table XI.M43-2, is revised to clarify that the methods described in GALL-SLR Report AMP XI.M41 may be used for cathodic protection, external coatings, and/or quality of backfill for the metal substrate of CFRP terminal ends of the CFRP-repaired piping.
- Detection of Aging Effects is revised to clarify that for HDPE piping and CFRP-repaired piping between terminal ends, only characteristics of backfill's type and material should be considered.
- Acceptance Criteria, Table XI.M43-3 from the version issued for public comment, and paragraphs 6(b)(ix) and 6(b)(x) are deleted because the methods in XI.M41 may be used for cathodic protection, external coatings, and/or quality of backfill for the metal substrate of CFRP terminal ends.
- Corrective Actions guidance related to cathodic protection is deleted as the methods of XI.M41 may be used for cathodic protection, external coatings, and/or quality of backfill for the metal substrate of CFRP terminal ends.

Associated technical basis for the Program Description, Preventive Actions, Detection of Aging Effects, Monitoring and Trending, Acceptance Criteria, and Corrective Actions changes are included in the Technical Bases Document, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M43.

NRC ID: 32-073, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," revision of AMP guidance such that exceptions or plant-specific AMPs would not be required.

Overview of Public Comment:

The comment recommends revising AMP guidance such that exceptions or plant-specific AMPs would not be required. The specific and prescriptive guidance contained in the draft Revision 1 of GALL-SLR will require exceptions and/or plant-specific AMPs for some stations. CFRP can be used for corrosion protection, as a semi-structural repair, or as a full structural replacement. It can also be installed as an internal lining or as an external wrap. The appropriate aging management differs for each of these six possible variations of CFRP installations. The new proposed AMP XI.M43, "HDPE Piping and CFRP Repaired Piping," only addresses an internal lining installed as a full structural replacement and other AMPs (e.g., XI.M41) have been revised to exclude all CFRP. Use of XI.M41 for any variation of CFRP would necessitate an exception. XI.M42 does not explicitly exclude internal corrosion protection CFRP linings but the guidance contained in this AMP does not apply for CFRP linings so exceptions would be required (e.g., qualified coating inspectors don't have any expertise in CFRP, aging effects in XI.M43 don't apply to CFRP, adhesion testing/etc. wouldn't apply to CFRP). The specific and prescriptive guidance contained in the draft Revision 1 of GALL-SLR will necessitate exceptions and/or plant-specific AMPs and should be removed.

Response:

The staff disagrees with the comment. The staff notes that XI.M43 mentions two exceptions. The first exception is in GALL-SLR Report, Volume 2, Revision 1, XI.M43, Element 4, "Detection of Aging Effects," which states that "Additional inspections, beyond those listed in Tables XI.M43-2 and XI.M43-3, may be appropriate if exceptions are taken to program element 2, "preventive actions," or in response to plant-specific OE." The second exception is in Element 4(a)(i) and 4(a)(ii). These two subparagraphs provide specific inspection.

The staff determined that these two exceptions are required because the exceptions provide guidance on the inspection frequency and how the inspection should be conducted for the buried HDPE and CFRP-repaired pipe such that the structural integrity of the subject pipes are maintained.

The staff notes that the NRC-approved CFRP-repaired pipes that have been installed in the nuclear plants have all been applied to the interior surface of the pipe. The staff has not received any licensing actions for CFRP application on the external surface of the pipe. The staff does not have any experience with licensing actions for CFRP applications on the external surfaces of the pipe, and therefore, the staff does not have the technical information at this time to expand the scope of AMP XI.M43. Therefore, AMP XI.M43 is applicable only to those pipes that have the CFRP applied to the internal pipe surface as structural lining. For a repair performed by CFRP that is out of the scope of AMP XI.M43, a licensee may submit a plant-specific AMP in its license renewal application. Examples of out-of-scope CFRP repair applications may include but not limited to (1) semi-structural lining of CFRP on the interior surface of a pipe, (2) semi-structural lining of CFRP on the exterior surface of a pipe, or (3) structural lining of CFRP on the exterior surface of a pipe. The staff will review the plant-specific AMP as part of license renewal process.

In the future, if a licensee wishes to apply CFRP to a pipe that is outside of the scope of AMP XI.M43 (e.g., semi structural repairs or exterior surface of the pipe), the staff will review the exceptions on a case-by-case basis.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-074, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," removal of reference to CFRP "repaired" piping. CFRP can be used to repair piping as a semi-structural repair that reinforces the original host pipe such that it meets design basis loading requirements.

Overview of Public Comment:

The comment recommends removal of reference to CFRP "repaired" piping from XI.M43, "HDPE Piping and CFRP Repaired Piping." CFRP can be used to repair piping as a semi-structural repair that reinforces the original host pipe such that it meets design basis loading requirements. However, the new proposed AMP XI.M43 does not address semi-structural repairs but rather only addresses full structural replacement of the original host pipe. The replacement CFRP piping does not take any credit for the host pipe and, as such, the original piping is abandoned, performs no intended function, and is not in-scope for LR.

Response:

The staff disagrees with the comment. The staff has approved relief requests from licensees to repair their degraded Class 3 pipes or as a preemptive full-structural repair. AMP XI.M43 is applicable to internal repair. The CFRP lining can be applied to the internal surface of the degraded pipe as a full structural, not semi or sub-structural repair. Licensees have not submitted a semi-structural CFRP application for the NRC review and approval. The staff does not provide guidance on components that are not installed in nuclear plants. Therefore, AMP XI.M43 does not address the semi or sub-structural repair.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-076, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," deletion of reference to flow blockage/fouling as HDPE and CFRP are not susceptible to flow blockage/fouling.

Overview of Public Comment:

The comment recommends deletion of the reference to flow blockage or fouling. HDPE and CFRP are not susceptible to flow blockage or fouling. Improved flow capacity is one of the benefits of installing HDPE or CFRP. Further, flow blockage is typically adequately addressed through the Maintenance Rule in that, when it occurs, it impacts the active system functions monitored through Maintenance Rule (e.g., flow test surveillances). The exception to this is portions of Fire Protection Systems that cannot be flow tested.

Response:

The staff disagrees with the comment. The staff recognizes that HDPE and CFRP-repaired pipes may be less susceptible than metals to fouling. However, it is not certain that the CFRP-repaired pipe or HDPE pipe will not have the fouling problems which can lead to flow blockage after many years of transporting raw water from an untreated water source. Therefore, the staff established AMP XI.M43 to monitor the CFRP-repaired pipe and HDPE pipe for fouling.

The staff recognizes that the maintenance rule includes flow test surveillances as noted by the commenter. The staff notes that the flow test surveillances are also part of Generic Letter (GL) 89-13, "Service Water System Problem Affecting Safety-Related Equipment," which is a part of AMP XI.M43, Element 3, "Parameters Monitored or Inspected." The guidelines of GL 89-13 include but not limited to the following: surveillance and control of biofouling, routine inspection, and a maintenance program to ensure that erosion, sediment deposition (silting), and biofouling cannot degrade the performance, and a review of maintenance, operating, and training practices and procedures. The Maintenance Rule by itself does not contain the specific inspections of the CFRP-repaired piping and HDPE piping as specified in the AMP for flow blockage and fouling. AMP XI.M43 in combination with GL 89-13 provides comprehensive inspection guidance to ensure the flow blockage or fouling is appropriately addressed.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-077, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," deletion of backfill preventive action recommendation for CFRP internal replacement piping.

Overview of Public Comment:

The comment recommends deletion of backfill preventive action recommendation for CFRP internal replacement piping. The CFRP piping addressed by this AMP are full structural replacements where no credit is taken for the host pipe. Complete degradation of the host pipe such that backfill could impact the CFRP liner during the 20-year renewed operating term is not credible.

Response:

The staff disagrees with the comment. The staff notes that inadequate backfill can damage the exterior surface of HDPE piping and the CFRP-repaired piping (e.g., metal-substrate between terminal ends of CFRP may be degraded completely). The staff recognizes that the NRC-approved CFRP-repaired pipe is analyzed such that CFRP layers will support the loads of the host pipe and that no credit is taken for the host pipe. However, the staff notes that the terminal ends of the CFRP-repaired pipe depend on the condition of the base metal of the host pipe. The base metal at the terminal ends of the host pipe needs to be in a sound condition. The staff finds that inadequate backfill on the exterior surface of the host pipe at the terminal ends may have adverse consequence to the CFRP-repaired pipe. Also, the inadequate backfill operation may damage the exterior surface of the HDPE such as if the back-hoe nicks the exterior surface of the HDPE pipe. Therefore, backfill prevention action will not be deleted from XI.M43.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-078, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," clarification of the frequency and scope in Table XI.M43-2 (now re-named XI.M43-3) apply to the tests and inspections in Element 3, "Parameters Monitored or Inspected."

The commenter requests the following changes to XI.M43, "HDPE Piping and CFRP Repaired Piping:"

- Part 1: Clarification of the frequency and scope in Table XI.M43-2 (now renamed XI.M43-3) that apply to the tests and inspections in Element 3, "Parameters Monitored or Inspected," paragraphs (a) and (b).

- Part 2: Elimination of a specific number and frequency of inspections for CFRP piping. Table XI.M43-2 (now renamed XI.M43-3) is structured like the similar table in XI.M41, "Buried and Underground Piping and Tanks," and recommends a specific number of inspections based on Preventive Action Categories. The scope of recommended inspections from Table XI.M43-2 (now renamed XI.M43-3) is 10 linear feet of piping, and these inspections are performed on a 10-year frequency. As written, Table XI.M43-2 recommends performance of inspections on 10-linear-ft sections of pipe which typically do not include terminal ends. Terminal ends are the areas of interest. The comment recommends elimination this recommendation for CFRP piping.

- Part 3: Deletion of the steel host pipe from the scope. The steel host pipe is addressed as a separate material in Table XI.M43-2 (now renamed XI.M43-3) with different criteria for determining the number of inspections. The steel material in Table XI.M43-2 (now renamed XI.M43-3) should be deleted as the host pipe is abandoned and performs no intended function and, as such, is not in-scope for LR (other than the terminal ends). Table XI.M43-2 (now renamed XI.M43-3) is structured to provide inspection scope based on total length of piping which does not apply to the terminal ends.

- Part 4: Revision to allow for the leakage tests recommended in Element 3 and required by ASME IWA-5000 in lieu of other inspections and testing recommended by the program. The leak tests recommended in Element 3 are sufficient to ensure the intended functions of buried HDPE and CFRP piping are maintained, and no other inspections or testing are required.

- Part 5: Revision to allow system leakage test to serve as an alternative to all testing and inspections since it verifies degradation has not impacted the piping intended functions regardless of whether degradation is internal, external, or at terminal ends (for CFRP). The alternative pressure testing clearly overlaps with leakage testing in that they are essentially equivalent tests.

Response:

Overall, the staff agrees in part to the comment. The staff agrees with the comment's Parts 1, 2, and 3. However, the staff disagrees with the comment's Parts 4 and 5.

Response to Part 1: The staff confirms that the frequency and scope in Table XI.M43-2 (now renamed Table XI.M43-3) for HDPE and CFRP materials apply to the tests and inspection in paragraphs (a) and (b) of Element 3. Element 4 provides the frequency of the inspections for HDPE and CFRP piping. As such, the staff did not make any revisions to Element 3, paragraphs (a) and (b).Response to Part 2: The staff agrees that after the repair, the CFRP laminate replaces the metal host pipe except at the CFRP terminal ends. The staff agrees that no guidance is needed to manage the aging of the metal host pipe between terminal ends and therefore, the staff deleted the number and frequencies of inspections for the metal host pipe in Table XI.M43-2 (now renamed XI.M43-3) as recommended by the comment. The NRC staff agreed with this comment because AMP XI.M43 provides guidance for the aging effects of the metal substrate of terminal ends. The staff agrees that the method of AMP XI.M41 may be used for quality of backfill, external coatings, and/or cathodic protection of the metal substrate of terminal ends, but the metal wall thickness at the terminal ends is addressed by AMP XI.M43 to ensure the metal substrate wall thickness meets the minimum design requirement. The staff revised Element 1 of AMP XI.M43 to clarify this. The staff agrees that the CFRP-repaired piping (i.e., the CFRP laminate between terminal ends and the metal substrate of terminal ends) can be affected by backfill. The staff agrees that the guidance in Element 4 for conducting inspection of backfill based on the number of inspections should also include the metal substrate of terminal ends, and therefore, the staff revised Table XI.M43-3 "External Surface Inspection of Buried and Underground HDPE Piping and CFRP Repaired Piping," and paragraphs 4(a) and 4(b).

Response to Part 3: For clarification, if CFRP repair is performed on the full length/run of a metal pipe or on the partial length/run of a metal pipe, the method of AMP XI.M41 may be used for quality of backfill, external coatings, and/or cathodic protection of the metal substrate of terminal ends, but the metal wall thickness at the terminal ends is addressed by AMP XI.M43. Furthermore, if CFRP repair is performed on the partial length/run of a metal pipe, the unrepaired partial length/run of the metal pipe is still in the scope of AMP XI.M41 and its aging is still managed by XI.M41. Based on the above and as indicated in the staff's response to Part 2 above, Table XI.M43-2 (now renamed XI.M43-3) is revised to address this comment by deleting the inspection guidance of the metal host pipe.

Response to Part 4: The staff disagrees with using the leakage testing in AMP XI.M43, Element 3, "Parameters Monitored or Inspected," and IWA-5000 in lieu of all other inspections

and testing specified in the AMP because the leakage testing by itself cannot monitor the incipient degradation of the structural integrity of CFRP-repaired and HDPE piping. The leakage test is useful only when a pipe has a through wall leak. The staff finds that the inspection and testing specified in the AMP will provide necessary monitoring of potential degradation that the leakage testing will not be able to detect. As such, the prescribed inspection and testing of the AMP in addition to the leakage testing will provide reasonable assurance of the structural integrity of the subject piping.

Response to Part 5: The comment proposed to allow system leakage test to serve as an alternative to all testing and inspections since it verifies degradation has not impacted the piping intended functions regardless of whether degradation is internal, external, or at terminal ends (for CFRP). The comment also asserted that the alternative pressure testing clearly overlaps with leakage testing in that they are essentially equivalent tests. The staff disagrees with using the leakage testing in AMP XI.M43, Element 3, “Parameters Monitored or Inspected,” in lieu of all other inspections and testing specified in the AMP because the leakage testing by itself cannot monitor the incipient degradation of the structural integrity of CFRP-repaired and HDPE piping. The staff finds that although the alternative pressure testing may overlap with leakage testing, pressure testing is not the same as leakage testing. The leakage test is useful only when a pipe has a through wall leak. The staff finds that the inspection and testing specified in the AMP will provide monitoring of potential degradation that the leakage testing will not be able to detect. As such, the inspection and testing of the AMP in addition to the leakage testing will provide reasonable assurance of the structural integrity of the subject piping.

Overview of Proposed Changes:

GALL-SLR Report, Volume 2, Revision 1, XI.M43, Element 1, “Scope of Program,” is revised in response to Part 2 of public comment to clarify that the methods described in AMP XI.M41 may be used for quality of backfill, external coatings, and/or cathodic protection of the metal substrate of terminal ends, but the metal wall thickness at the terminal ends is addressed by AMP XI.M43.

AMP XI.M43, Element 4, “Detection of Aging Effects,” Table XI.M43-3 is revised to clarify that the method of AMP XI.M41 may be used for quality of backfill, external coatings, and/or cathodic protection of the metal substrate of terminal ends, but the metal wall thickness at the terminal ends is addressed by AMP XI.M43.

AMP XI.M43, Element 4, “Detection of Aging Effects,” paragraphs (a) and (b) are revised to add the following statement,” For the CFRP-repaired pipe, the 10 linear feet of pipe should include at least one terminal end.”

Associated technical basis for the Scope of Program and Preventive Actions, and Detection of Aging Effects changes are included in the Technical Bases Document, Table 2-33, “GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” Section XI.M43.

NRC ID: 32-079, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," clarify the contradiction between element 3, "Parameters Monitored or Inspected," and element 4, "Detection of Aging Effects," on the terminal ends of CFRP inspections.

The comment requests clarification of the recommendation of Element 4, "Detection of Aging Effects," paragraph (c)(iii), which appears to contradict Element 3, "Parameters Monitored or Inspected," paragraph (b)(ii). Element 4 paragraph (c)(iii) states "…the terminal ends of CFRP must be inspected by ultrasonic examination during each inspection interval." Element 3 paragraph (b)(ii) specifies that volumetric examination of the terminal end regions be performed and included examples of NDE techniques other than ultrasonic examination.

Response:

The staff agrees with the comment. The staff revised paragraph (b)(ii) of Element 3 and paragraph (c)(iii) of Element 4 to establish consistency.

Overview of Proposed Changes:

The NRC staff edited GALL-SLR Report, Volume 2, Revision 1, XI.M43, Element 3, "Parameters Monitored or Inspected," to say the following:

Volumetric examination of the terminal end regions of the CFRP-repaired piping is performed using a nondestructive examination (NDE) technique, e.g., acoustic tap, ultrasonic, electrical, magnetic, thermal, microwave, or other applicable nondestructive methods.

- Interrogate the CFRP-repaired piping at the terminal ends region to detect delamination of layers and debonding of laminate from metal substrate.
- Establish a thickness profile of the metal substrate at the CFRP terminal ends to verify conformance with design requirements.

Please note, the language in the text also includes a footnote after "acoustic tap" providing a additional information on acoustic taps.

The staff also added a footnote to explain acoustic tap in the revised paragraph.

Staff revised Element 4, "Detection of Aging Effects," by deleting paragraph (c)(iii), updating Table XI.M43-3, and adding a paragraph (e) stating the following:

> For CFRP-repaired piping, the metal substrate at CFRP terminal ends is inspected by ultrasonic examination (or any reliable NDE technique capable of measuring metal wall thickness) from the pipe's internal surface during each inspection interval to ensure the metal substrate wall thickness meets the minimum design requirement.

Please note, however, that "For CFRP-repaired piping" only appears in Element 4 paragraph €. The entries in Table XI.M43-3 start with "The metal substrate."

Associated technical basis for the Parameters Monitored or Inspected, and Detection of Aging Effects, changes are included in the Technical Bases Document, Table 2 33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M43.

NRC ID: 32-080, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," clarification of paragraph numbering for CFRP piping in Element 3, "Parameters Monitored or Inspected."

Overview of Public Comment:

The comment recommends correction of the XI.M43, "HDPE Piping and CFRP Repaired Piping," paragraph numbering for Element 3, "Parameters Monitored or Inspected."

Response:

The staff agrees with the comment.

Overview of Proposed Changes:

The staff made an editorial change in the numbering format of Element 3, "Parameters Monitored or Inspected."

NRC ID: 32-081, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," removal of copper alloy and aluminum alloy from Table XI.M43-3, "Cathodic Protection Acceptance Criteria."

Overview of Public Comment:

The comment recommends removal of copper alloy and aluminum alloy from Table XI.M43-3, "Cathodic Protection Acceptance Criteria." Table XI.M43-2, "Inspection of Buried HDPE Piping and CFRP Repaired Piping," only refers to steel piping while Table XI.M43-3 refers to steel, copper alloy, and aluminum alloy piping. It is highly unlikely that any stations have copper alloy or aluminum alloy piping that has a large enough diameter to allow for installation of CFRP.

Response:

The staff agrees with the comment on the removal of copper alloy and aluminum alloy from Table XI.M43-2 (now re-named Table XI-M43-3 because of changes made in response to a different comment). In addition the staff deleted Element 6, "Acceptance Criteria," paragraph 6(b)(ix) and the entire Table XI.M43-3 with its associated footnotes as they related to managing metal host pipe (i.e., copper and aluminum alloy) not repaired by CFRP, and metal substrate of CFRP terminal ends that are managed by AMP XI.M41. In these changes the staff intends for AMP XI.M43 to be less material specific.

Overview of Proposed Changes:

The staff deleted "Acceptance Criteria," paragraph 6(b)(ix) and Table XI.M43-3 with its associated footnotes and as they related to managing metal host pipe not repaired by CFRP and metal substrate of CFRP terminal ends.

Associated technical basis for the Acceptance Criteria changes are included in the Technical Bases Document, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI,

Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M43.

NRC ID: 32-082, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," revision of the AMP to eliminate all testing and inspections for HDPE or CFRP piping fully backfilled in controlled low-strength material.

Overview of Public Comment:

The comment recommends revision of the XI.M43, "HDPE Piping and CFRP Repaired Piping," to eliminate all testing and inspections for HDPE or CFRP piping fully backfilled in controlled low-strength material. No external visual inspections are warranted for HDPE or CFRP piping backfilled in controlled low-strength material or concrete. The concern for metallic piping backfilled in controlled low-strength material or concrete (i.e., infiltration of groundwater through the backfill potentially resulting in corrosion of the metallic piping) is not applicable to HDPE or CFRP. Non-safety-related HDPE is not managed by this AMP and inspection of non-safety-related CFRP piping is not warranted. XI.M41 states that no inspections are recommended for polymeric piping fully backfilled in controlled low-strength material.

Response:

The staff disagrees with the comment regarding elimination of guidance on backfill quality. The staff notes that inadequate backfill quality can damage the exterior surface of HDPE piping and the CFRP-repaired piping (e.g., metal-substrate between terminal ends of CFRP may crack or be degraded completely). Therefore, the guidance for the quality of backfill in AMP XI.M43 Program Description that states, "[p]reventive and mitigative techniques for the HDPE piping and the CFRP-repaired piping between CFRP terminal ends may include the quality of backfill to prevent damage to potentially exposed external surfaces," as well as in Element 2 Preventive Actions paragraph (b) and Element 4 Detection of Aging Effects Table XI.M43-3 will not be deleted.

In addition, the staff notes that the commenter stated that "… XI.M41 states that no inspections are recommended for polymeric piping fully backfilled in controlled low-strength material…." In response to this part of public comment, the staff notes that AMP XI.M43 Element 2 Preventive Action paragraph (b) has similar guidance on backfill quality which states, in part, that, "Alternatively, backfill quality may be demonstrated by plant records of the original code of construction requirements, or by examining the backfill while conducting the inspections described in the "detection of aging effects" program element of this AMP…."

The staff disagrees with commenter which states that "Non-safety-related HDPE is not managed by this AMP and inspection of non-safety-related CFRP piping is not warranted…." In response to this part of public comment, the staff notes that AMP XI.M43 Program Description and Element 1 Scope of Program include safety-related and in-scope non-safety-related buried and underground HDPE piping and CFRP-repaired piping. The staff further notes that if buried and underground HDPE and CFRP-repaired piping are non-safety-related but are in the scope of license renewal, their aging management is warranted by AMP XI.M43 in accordance with 10 CFR Part 54.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-083, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," removal of reference to coatings in the Acceptance Criterion and Table XI.M43-2 (now re-named XI.M43-3) since HDPE piping is not coated.

Overview of Public Comment:

The comment recommends that the NRC staff edit XI.M43, "HDPE Piping and CFRP Repaired Piping," to remove reference to coatings in the Element 6, "Acceptance Criterion," for HDPE piping provided in paragraph (a)(ii), and from Table XI.M43-2 (now re-named XI.M43-3), "Inspection of Buried HDPE Piping and CFRP-Repaired Piping," Note C.b.i, which states, "coatings and backfill are provided in accordance with the "preventive actions" program element of this AMP." HDPE piping is not coated.

Response:

The staff agrees with the comment. The staff removed coating guidance for HDPE piping in XI.M43, Element 6, "Acceptance Criterion." Table XI.M43-2 (now re-named Table XI.M43-3 because of changes made in a response to a different comment) has coating related guidance for CFRP repaired piping, but there is no guidance for coatings that is applicable to HDPE piping.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, XI.M43, Element 6, "Acceptance Criterion," paragraph (a)(ii) is revised to remove coatings from the acceptance criteria for HDPE piping.

Associated technical basis for the "Detection of Aging Effects and Acceptance Criteria changes are included in the Technical Bases Document, Table 2 33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M43.

NRC ID: 32-084, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," elimination of the recommended minimum length of piping for inspections (10 linear feet).

Overview of Public Comment:

The Comment recommends that the NRC staff edit XI.M43, "HDPE Piping and CFRP Repaired Piping," to eliminate the recommended minimum length of piping for inspections (10 linear feet). Inspection of 10 linear feet of piping during each inspection is not necessary to assess the condition of buried piping. The minimum inspection length recommendation precludes the use of vacuum excavation "potholing" for inspection of buried piping since vacuum excavation units are typically unable to expose a 10-foot length of piping.

Comment further states that alternatively, inclusion of a caveat similar to other AMPs (e.g., XI.E6, XI.M32, XI.M33, XI.M38) providing the option for a plant specific alternative sampling methodology and sample sizes with the technical justification included as part of the program's documentation.

Response:

The staff disagrees with the comment. Table XI.M43-2 is re-named Table XI-M43-3, “External Surface Inspection of Buried and Underground HDPE Piping and CFRP Repaired Piping,” due to changes made in response to a different comment. The staff notes that the inspection of 10 linear feet of piping is specified in Element 4, Table XI.M43-3, paragraphs (a)(i), (b)(i), and (b)(iii).

Paragraph (b)(i) states, in part, that when conducting inspection of backfill based on the number of inspections, 10 linear feet of the backfill are exposed for each inspection.

Paragraph (c)(i) states that 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.

Paragraph (c)(ii) states that 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.

The staff notes that the 10 linear feet piping length in these paragraphs provide an alternative (i.e., relaxation) to the specific inspections. These inspections would occur in the locations determined to be the highest risk based on degradation susceptibility and the consequences of failure. Based on its engineering judgement, the NRC staff considers the 10-foot length a reasonable representation of the entire length of the pipe for determining the pipe’s susceptibility to degradation. This length is also consistent with other AMPs. Although this length, may preclude the use of “potholing,” this AMP is guidance. Licensees are free to propose alternative plans, which the NRC staff will review for compliance with the relevant regulations.

The NRC staff did not add a caveat to the AMP providing an alternative for plant-specific sampling methodology and sample sizes because such a caveat is unnecessary. This AMP is guidance, meaning that, even without a caveat, licensees are free to propose plant-specific alternatives. If licensees choose to do so, the NRC staff will review the alternatives as well as the accompanying technical justifications for compliance with the relevant regulations.

The staff notes that AMP XI.M43 was developed to manage the CFRP-repaired piping (i.e., CFRP laminate and metal substrate of CFRP terminal ends). However, as related to the discussion on minimum length of piping for inspections, categories A, B, C, and D in Table XI.M43-3 “External Surface Inspection of Buried and Underground HDPE Piping and CFRP Repaired Piping” with its associated footnotes apply to buried and underground metal pipe aging that is in the scope of GALL-SLR Report AMP XI.M41. Therefore, the staff deleted A, B, C, and D categories in Table XI.M43-3 with its associated footnotes.

Overview of Proposed Changes:

For clarification, the staff deleted A, B, C and D categories in Table XI.M43-2 (now re-named XI.M43-3) because these categories apply to metal host pipe aging that is managed by GALL-SLR Report AMP XI.M41. The staff also deleted Table XI.M43-2 (now renamed XI.M43-3) footnotes A, B, and C and D.

Associated technical basis for the Detection of Aging Effects changes are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M43.

NRC ID: 32-085, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," deletion of Element 4 piping inspection location selection guidance that does not apply to HDPE and CFRP piping.

Overview of Public Comment:

The Comment recommends that the NRC staff edit XI.M43, "HDPE Piping and CFRP Repaired Piping," to delete the second sentence of paragraph (d) of Element 4, as the piping inspection location selection guidance does not apply to HDPE and CFRP piping. Coating type, coating condition, cathodic protection efficacy, and soil resistivity are not relevant to HDPE piping. These factors are also not relevant to CFRP piping, other than at terminal ends, since these factors only affect the host pipe, which is abandoned, performs no intended function, and is not in-scope for LR. Further, since CFRP is installed to replace degraded piping, the original coating is expected to be significantly degraded. Backfill characteristics are not relevant to CFRP piping since the host pipe provides a barrier between the CFRP replacement and the backfill and complete degradation of the host pipe during the period of extended operation is not credible.

Response:

The staff agrees with the comment, in part, specifically with the recommendations to delete, "Characteristics such as coating type (i.e., material type), coating condition, cathodic protection efficacy, soil resistivity, pipe contents, and pipe function are considered" in the second sentence of paragraph (d) of Element 4.

The staff disagrees with the comment, in part, specifically with the recommendations to delete that commenter recommends delete "Backfill characteristics" in the second sentence of paragraph (d) of Element 4. Backfill can have an effect on the HDPE piping and CFRP-repaired piping between terminal ends when the metal substrate between terminal ends is degraded completely. It is important to note that one of the main purposes of the repair of the existing buried and underground metal pipe by CFRP liner is to mitigate the degradation of the metal pipe and loss of material due to corrosion. After installation of the CFRP liner, the aging of the metal substrate between terminal ends will no longer be managed, there is no way to reasonably quantify the amount of metal loss due to corrosion, and reasonably be certain that the CFRP liner will not be exposed to backfill over time.

Overview of Proposed Changes:

For clarification, the staff will revised AMP XI.M43, Element 4, “Detection of Aging Effects,” paragraph (c), (formerly paragraph (d)) read as follows:

> Piping inspection location selection: Piping inspection locations are selected based on risk (i.e., susceptibility to degradation and consequences of failure). For HDPE piping and CFRP-repaired piping between terminal ends, characteristics such as backfill type and material are considered. Opportunistic examinations of nonleaking pipes may be credited toward examinations if the location selection criteria are met.

Associated technical basis for the Detection of Aging Effects changes are included in the Technical Bases Document Supplement 1, Table 2-33, “GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” Section XI.M43.

NRC ID: 32-086, Andrew N. Mauer (NEI) - XI.M43, “HDPE Piping and CFRP Repaired Piping,” revision to state that the acceptance criterion provided in Element 6, paragraph (b)(i) only applies to the terminal ends.

Overview of Public Comment:

The comment recommends that the NRC staff edit XI.M43, “HDPE Piping and CFRP Repaired Piping,” to clarify Element 6, “Acceptance Criteria,” paragraph (b)(i), applies solely to terminal ends. Since the piping is abandoned and serves no purpose, the degraded external coating of the host pipe is not required, except for the terminal ends.

Response:

The staff agrees with the comment. The staff deleted paragraph (b)(i) of Element 6 since the aging of any segment of metal host pipe is not repaired by CFRP and the metal substrate at terminal ends of CFRP-repaired pipe are managed by AMP XI.M41.

Overview of Proposed Changes:

The staff deleted Element 6, “Acceptance Criteria,” paragraph (b)(i) of because the statements in this paragraph are not relevant for the acceptance criteria.

Associated technical basis for the Acceptance Criteria changes are included in the Technical Bases Document Supplement 1, Table 2-33, “GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” Section XI.M43.

NRC ID: 32-087, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," revision to the acceptance criterion provided in Element 6, paragraph (b)(iii) to state that it only applies to the terminal ends.

Overview of Public Comment:

The comment states for XI.M43, "HDPE Piping and CFRP Repaired Piping," the following:

Part 1: Revise the acceptance criterion provided in paragraph (b)(iii) of Element 6 to state that it only applies to the terminal ends. The host pipe is expected to be degraded, and there is no required minimum wall thickness since the CFRP replacement is a full structural replacement, so the host piping is abandoned, performs no intended function, and is not in-scope for LR (other than the terminal ends).

Part 2: Further, projection of wall loss of host pipe at terminal ends through the end of the period of extended operation (PEO) is unwarranted and contrary to guidance used in other AMPs where degradation is projected to the next inspection. As a sample-based program, XI.M43 assumes that the inspection results are representative or bounding of the general condition of the similar population of components managed by the AMP. If inspection results indicate that the piping terminal ends will remain above minimum required wall-thickness through the next scheduled inspection (10 years) using an appropriately conservative projection methodology, then the results are acceptable and demonstrate that there is reasonable assurance that the intended functions of the overall population of similar components will be maintained through the next scheduled inspection.

Part 3: Given the uncertainty involved in projecting external corrosion of buried piping (i.e., no way to know when the coating failed and corrosion began to occur), a conservative corrosion rate is typically assumed to determine remaining life (16 mpy for pitting corrosion per NACE guidance). Even if inspection results indicate intact coating, it is unknown if/when the coating will degrade and allow initiation of corrosion. The 10-year inspection frequency assumes that intact coating could potentially fail immediately after reburial resulting in up to ~160 mil pitting prior to the next inspection. This is acceptable since the minimum required wall thickness for localized/pitting corrosion is based on hoop stress and, as such, minimum required wall thickness would be expected to be maintained for relatively low pressure buried piping systems. The same cannot be said when making a 30-year projection (assuming inspections performed at/near the beginning of the 10-year period prior to the PEO and projecting through the end of the PEO). Projection of corrosion through the end of the PEO (up to 30 years) is not an appropriate acceptance criterion to drive expanded sample inspections performed within 4-10 years (depending on timing of initial inspection).

Response:

Overall, the staff agrees with the comment.

Response to Part 1: The revised paragraph (b)(iii) of Element 6 to clarify that it only applies to the terminal ends.

Response to Parts 2 and 3: The staff revised Element 6 paragraph (b)(iii) to clarify that the projection of wall thickness loss is for the metal substrate at the CFRP terminal end through to the end of the next 10-year in-service inspection interval. The staff also revised Element 6 paragraph (b)(viii) to clarify that backfill inspection and acceptance is for the external surface of

the CFRP laminate and not for the pipe's external coatings or the surface of the pipe and relabeled it (b)(vii). In addition, the staff deleted Element 6 paragraphs (b)(i), (b)(ix), (b)(x), and Table XI.M43-3 because they are related to coatings, backfill, and/or cathodic protection of the metal pipe not repaired by CFRP. The staff deleted these paragraphs in response to other comments, but mention them here to help clarify the number of paragraphs in Element 6(b).

Overview of Proposed Changes:

The staff relabeled Element 6 paragraph (b)(iii) to Element 6 paragraph (b)(ii) and revise the paragraph to state that: "The measured wall thickness of the metal substrate at terminal ends of the CFRP-repaired piping that is extrapolated to degrade with a loss of material to the end of the next 10-year inservice inspection interval shall meet the minimum design wall thickness requirements." CFRP-repaired piping min design wall thickness is required by ASME Code or construction code requirements.

The staff deleted Element 6 paragraphs (b)(i), (b)(ix), (b)(x), and Table XI.M43-3 because they are related to coatings, backfill, and/or cathodic protection of the metal pipe not repaired by CFRP.

The staff relabeled Element 6 paragraph (b)(viii) to (b)(vii) and revised the paragraph to state that: "Backfill is acceptable if the inspections do not reveal evidence that the backfill caused damage to the external surface of the CFRP laminate."

Associated technical basis for the Acceptance Criteria changes are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M43.

NRC ID: 32-088, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," removal of reference to NACE qualification for coating inspectors and CP4 since NACE no longer exists.

Overview of Public Comment:

The Comment recommends the NRC staff edit XI.M43, "HDPE Piping and CFRP Repaired Piping," to remove reference to National Association of Corrosion Engineers (NACE) qualification for coating inspectors and Cathodic Protection Specialist (CP4) since NACE no longer exists.

Response:

The staff disagrees with the comment. The staff is aware that NACE has merged with the Society for Protective Coatings to form the Association for Materials Protection and Performance. However, the AMPP website still identifies NACE as their designator. The staff added a footnote to AMP XI.M43, Element 2 to state the following:

NACE International and the Society for Protective Coatings (SSPC) merged in 2021 and created the Association for Materials Protection and Performance (AMPP).

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, AMP XI.M43, Element 2, "Preventive Actions," paragraph (b) is revised to include the following footnote:

NACE International and the Society for Protective Coatings (SSPC) merged in 2021 and created the Association for Materials Protection and Performance (AMPP).

The staff revised AMP XI.M43 Element 2, "Preventive Actions," paragraphs (a) and (b). Staff mentions these changes here because they are related to NACE. The revised paragraphs read as follows:

a. The methods of GALL-SLR Report AMP XI.M41 are used for cathodic protection, external coatings, and/or quality of backfill of the metal substrate of terminal ends of the CFRP-repaired piping, but the wall thickness at the terminal ends is addressed by AMP XI.M43.

b. The CFRP between terminal ends of the CFRP-repaired piping may come in contact with backfill when the metal substrate between terminal ends are degraded completely. Backfill is consistent with Section 5.2.3 of the National Association of Corrosion Engineers (NACE[1]) SP0169-2007 (NACE 2007-TN9467), or Section 3.6 of NACE RP0285-2002 (NACE 2002-TN9466), or original Construction Code. The staff considers backfill that is located within 6 inches of the piping that meets ASTM D 448-08 (ASTM 2008-TN9461) size number 67 (size number 10 for polymeric piping materials) to meet the objectives of NACE SP0169-2007, NACE RP0285-2002, and original Construction Code. Alternatively, backfill quality may be demonstrated by plant records of the original code of construction requirements, or by examining the backfill while conducting the inspections described in the "detection of aging effects" program element of this AMP

Associated technical basis for the Preventive Actions changes are included in the Technical Bases Document, Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M43.

NRC ID: 32-089, Andrew N. Mauer (NEI) - XI.M43, "HDPE Piping and CFRP Repaired Piping," removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue.

Overview of Public Comment:

The comment recommends removal of prescriptive corrective action recommendations since the appropriate corrective actions are highly dependent on the specific details of the issue. The recommended corrective actions in XI.M43, Element 7 "Corrective Actions," paragraph (a), may not be warranted depending on the specific details from the initial inspections. The Element 7, paragraph (a), guidance states that sample expansion inspections or repair/replacement if initial inspections identify degradation that, when projected, would require replacement of the

[1] NACE International and the Society for Protective Coatings (SSPC) merged in 2021 and created the Association for Materials Protection and Performance (AMPP).

component prior to the end of the subsequent period of operation. Projecting through the end of the subsequent period of extended operation as the basis for expanded sample inspections is overly conservative, as discussed in a previous comment 32-087. Further, given the uncertain degradation rate of buried externally coated components, it is unclear how this recommendation is to be implemented.

The recommended corrective actions in Element 7, paragraphs (b), (c), and (d) are unnecessary and already adequately addressed through station CAP processes.

Response:

The staff disagrees with the comment except the portion of the comment regarding the projection of degradation. The staff agrees that the projection of degradation should be through the end of the next 10-year in-service inspection rather than the period of extended operations in Element 7 Corrective Actions paragraph (a). Therefore, the staff replaced the wording “the period of extended operations” with “the end of the next 10-year inservice inspection interval” in Element 7 paragraph (a). The staff notes that all guidance in Element 7 of AMP XI.M43 is consistent with Element 7 of other AMPs in the GALL-SLR Report, Revision 1.

The staff disagrees with the comment that states, “The recommended corrective actions in Element 7 paragraphs (b), (c), and (d) are unnecessary and already adequately addressed through station CAP processes.” The CAP process of one plant may be different than the CAP process of another plant. Consistent guidance across the industry may be useful when designing a program that is compliant with 10 CFR 54. Based on the Staff’s technical and engineering judgement, a plant’s station corrective action program, without the supplemental use of PCAs, may not provide the necessary assurance that a sufficient number of additional inspections have been performed

Element 7 of AMP XI.M43 describes corrective actions which follow the same approach as AMP XI.M41. The corrective actions in XI.M43 are no more prescriptive than the corrective actions in XI.M41 or other AMPs. The corrective actions in Element 7 of XI M43 provide guidance on an acceptable initial number of inspections, sample inspections, analysis to determine the extent of condition inspections, and timing of the examinations. This guidance provides a fundamental concept of using inspections to monitor the structural integrity of the CFRP-repaired piping and HDPE piping. The staff noted that corrective actions of Element 7 are not prescriptive because they provide generic guidance. The staff recognizes that the appropriate corrective actions are highly dependent on the specific details of the issue. As such, Element 7 provides generally acceptable corrective actions. Element 7 provides a corrective action framework in which a licensee could manage the specific details of the degradation issue related to CFRP-repaired piping and HDPE piping.

In looking at Element 7 to respond to this comment, the staff decided to make few additional changes. Although these were not prompted by this comment, staff notes them here for the sake of completeness. The staff deleted the wording “of the base metal” and replaced the wording “loss of material” with “degradation (e.g., loss of material, cracking, delamination, debonding, and/or blistering)” in AMP XI.M43 Element 7 paragraph (a). In addition, the staff replaced the wording “cracking” with “degradation (e.g., loss of material, cracking, delamination, debonding, and/or blistering)” in AMP XI.M43 Element 7 paragraph (d) (renamed paragraph (c)).

Overview of Proposed Changes:

The staff replaced the wording “the period of extended operations” with “the end of the next 10-year inservice inspection” in Element 7 paragraph (a).

The staff deleted the wording “of the base metal” and replaced the wording “loss of material” with “degradation (e.g., loss of material, cracking, delamination, debonding, and/or blistering)” in Element 7 paragraph (a).

The staff replaced the wording “cracking” with “degradation (e.g., loss of material, cracking, delamination, debonding, and/or blistering)” in Element 7 paragraph (d) (renamed paragraph (c)).

Associated technical basis for the Corrective Actions changes are included in the Technical Bases Document, Supplement 1, Table 2-33, “GALL-SLR Report, Revision 1, Differences From Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” Section XI.M43.

NRC ID: 32-090, Andrew N. Mauer (NEI) - Table A.4, “Group 4 Structures (Containment Internal Structures, Excluding Refueling Canal),” combination of GALL-SLR AMR line items III.A4.T-36 and III.A4.T-37 into one consolidated item.

Overview of Public Comment:

The comment relates to GALL-SLR Report (NUREG-2191), Volume1, Revision 1, Table A.4, “Group Structures (Containment Internal Structures, Excluding the Refueling Canal) (Continued)”, requesting to combine line items III.A4.T-36 and III.A4.T-37 into one consolidated item, or alternatively provide additional justification or explanation for maintaining both entries.

Response:

The staff agrees with the comment because the only difference between line items III.A4.T-36 and III.A4.T-37 is that line item III.A4.T-37 has a contingency when there is evidence of combined aging effects in areas of high tensile stresses.

Overview of Proposed Changes:

Current line item III.A4.T-36 in Draft GALL-SLR Report, Volume1, Revision 1, Table A.4 will be deleted. Current line item III.A4.T-37 will be changed (renumbered) to line item III.A4.T-36. These changes essentially combine current line items III.A4.T-36 and III.A4.T-37 into one line item.

Associated technical basis for the change in the Program Description is included in the Technical Bases Document, Supplement 1, Table 2-6. “New Aging Management Review Items Added in GALL-SLR Report, Revision 1, Chapter III, Structures and Component Support,” row III.A4.T-36.

NRC ID: 32-091, Andrew N. Mauer (NEI) - XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," revision to clarify inspections and aging management of cables that are coated with fire retardant material.

Overview of Public Comment:

The comment recommends for the NRC staff to revise XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," to clarify the definition of ALE to avoid unintentionally limiting the scope of inspections and aging management of cables.

Response:

The staff agrees that the proposed wording in draft for comment GALL-SLR, Volume 2, Revision 1, could create confusion and unintentionally limit the scope. Therefore, the staff revised the adverse localized environment definition on page XI-5 of XI.E1. The staff's revised wording makes it clear that an adverse localized environment is an environment that exceeds the most limiting environment for electrical insulation of both cables and connectors, including both cables and connectors coated in fire-retardant material. The staff also agrees that "coated with fire-retardant material" can be deleted on page XI-7 of XI.E1 to avoid confusion, by making it clear that that language did not only apply to cables and connectors coated in fire retardant material.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, XI.E1, Program Description, is revised to state:

> 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 and connectors, including those that are coated with fire-retardant material.

The Detection of Aging Effects discussion is revised to state:

Cables and electrical connections are inspected to identify cable and connection insulation installed in an adverse localized environment.

Associated technical basis for the changes in the Program Descriptions and Detection of Aging Effects are included in the Technical Bases Document, Supplement 1, Table 2-35, "GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.E1.

NRC ID: 32-092, Andrew N. Mauer (NEI) - X.E1, "Environmental Qualification of Electric Equipment," revision to clarify that mechanical components associated with electrical equipment (such as gaskets, seals, O-rings, etc.), in the scope of this AMP are considered sub-components.

Overview of Public Comment:

The comment recommends that the NRC staff edit X.E1, "Environmental Qualification of Electric Equipment," to clarify that mechanical components associated with electrical equipment (such as gaskets, seals, O-rings, etc.) in the scope of this AMP are considered sub-components.

Response:

The staff disagrees with the comment because these proposed edits may have caused confusion. However, the staff has revised X.E1 due to another comment, in a way that the staff thinks avoids the confusion that the proposed additions may have caused but addresses the concerns motivating the requested edits.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, X.E1, Program Description, is revised to clarify the scope of mechanical equipment and components that are included in the AMP. The following text is included:

> Qualification under § 50.49 addresses the electrical and mechanical components that are relied upon to ensure the functional capability of the equipment being qualified under the postulated design basis conditions. The mechanical components can include age sensitive items such as gaskets, seals, or O-rings.

Associated technical basis for the change in the Program Description is included in the Technical Bases Document, Supplement 1, Table 2-32, "GALL-SLR Report, Revision 1, Chapter X, Time-Limited Aging Analysis, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section X.E1.

NRC ID: 32-093, Andrew N. Mauer (NEI) - XI.E3A, XI.E3B and XI.E3C, on Electrical Insulation for Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, removal of requirement for level control alarm at central location or control room.

Overview of Public Comment:

The comment recommends the staff edit XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," and XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," to remove the guidance for locating level control alarms at a central location or the control room.

Response:

The staff disagrees with the suggestion to remove the words "central location" or "the control room" because these are acceptable locations for level control alarms. However, the staff modified AMPs XI.E3A, XI.E3B, and XI.E3C to provide clarity and guidance on acceptable level control alarms, including locations, to ensure that the cause of level alarms is appropriately and expeditiously identified and addressed.

Overview of Proposed Changes:

The NRC staff revised the following GALL-SLR Report Volume 2, Revision 1 AMPs and program elements to provide guidance on acceptable level control alarms to ensure that the cause of level alarms is appropriately and expeditiously identified and addressed.

- XI.E3A, Program Description, Parameters Monitored
- XI.E3B, Program Description, Parameters Monitored
- XI.E3C. Program Description, Parameters Monitored

Associated technical basis for the changes in the Program Descriptions are included in the Technical Bases Document, Supplement 1, Table 2-35, "GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," sections XI.E3A, XI.E3B, and XI.E3C.

NRC ID: 32-094, Andrew N. Mauer (NEI) - XI.E3A, XI.E3B and XI.E3C, on Electrical Insulation for Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, deletion of the word "continuous" from the level monitoring device description.

Overview of Public Comment:

The comment recommends for the NRC staff to edit XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," and

XI.E3C, “Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” to delete the word “continuous” from the level monitoring device description, as use of this word could imply that any temporary interruption of level detection systems would negate their use in justifying less frequent inspections.

Response:

The staff agrees with the comment and implemented all recommended changes in the comment.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, XI.E3A, Element 1, “Program Description” and Element 2, “Preventive Actions,” revise expectations related to level monitoring devices by deleting the word “continuous” to read as follows, “Credit for water level monitoring equipment can be taken if such devices have self-monitoring features and generate failure alarms in a location that is easily identifiable and observable to ensure that the cause of the alarm is appropriately and expeditiously identified and addressed (e.g., a central location, control room, etc.)….” The reliability and methods of ensuring operation of level monitoring devices are justified and documented. ”

In GALL-SLR Report, Volume 2, Revision 1, XI.E3B, Element 1, “Program Description” and Element 2, “Preventive Actions,” revise the expectations related to level monitoring devices by deleting the word “continuous” to read as follows, “Credit for water level monitoring equipment can be taken if such devices have self-monitoring features and generate failure alarms in a location that is easily identifiable and observable to ensure that the cause of the alarm is appropriately and expeditiously identified and addressed (e.g., a central location, control room, etc.)….” “The reliability and methods of ensuring operation of level monitoring devices are justified and documented.”

In GALL-SLR Report, Volume 2, Revision 1, XI.E3C, Element 1, “Program Description” and Element 2, “Preventive Actions,” revise the expectations related to level monitoring devices by deleting the word “continuous” to read as follows, “Credit for water level monitoring equipment can be taken if such devices have self-monitoring features and generate failure alarms in a location that is easily identifiable and observable to ensure that the cause of the alarm is appropriately and expeditiously identified and addressed (e.g., a central location, control room, etc.)….” The reliability and methods of ensuring operation of level monitoring devices are justified and documented.”

Associated technical basis for the changes in the Program Description and Preventive Actions changes are included in the Technical Bases Document, Supplement 1, Table 2-35, “GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” Sections XI.E3A, XI.E3B, and XI.E3C.

NRC ID: 32-095, Andrew N. Mauer (NEI) - XI.E3A, "Electrical Insulation For Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," deletion of the word "potentially" in relation to exposure to moisture, wetting, or submergence of cables.

Overview of Public Comment:

The comment recommends for NRC staff to delete the word "potentially" from the AMP Program Description in relation to exposure to moisture, wetting, or submergence of cables from XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The word "potentially" is ambiguous and not supported by or explained by the draft for comment Technical Bases Document, Supplement 1.

Response:

The staff disagrees with the comment because the word "potentially" in the context of the areas identified by the comment is necessary to capture environmental unknowns associated with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring. This ensures that inaccessible cables are conservatively scoped into the AMP and adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function. Using this term in this context is consistent with EPRI aging management implementation guidance in 3002010641 (low voltage cables) and 3002000557 (medium voltage cables) as these EPRI reports assume a cable to be wet if it cannot be verified that it is dry in those inaccessible locations; and therefore, aging management actions are performed on those cables.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, XI.E3A, Element 1, "Program Description" is revised to state:

> The word 'potentially' is necessary to capture environmental unknowns associated with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring (i.e., a cable is assumed to be wet if it cannot be verified that it is dry in inaccessible locations; and therefore, aging management actions are performed on those cables). This ensures that inaccessible cables are conservatively scoped into the AMP and adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function.

Associated technical basis for the changes in the Program Description change are included in the Technical Bases Document, Supplement 1, Table 2-35, "GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.E3A.

NRC ID: 32-096, Andrew N. Mauer (NEI) - XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," deletion of the word "potentially" in relation to cable exposed to significant moisture.

Overview of Public Comment:

The comment recommends that the NRC staff delete the word "potentially" from AMP Program Description in relation to exposure to significant moisture in XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Response:

The staff partially disagrees with the comment because the word "potentially" in the context of the areas identified by the comment is necessary to capture environmental unknowns associated with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring. This ensures that inaccessible cables are conservatively scoped into the AMP and adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function. Using this term in this context is consistent with EPRI aging management implementation guidance in 3002010641 (low voltage cables) and 3002000557 (medium voltage cables) as these EPRI reports assume a cable to be wet if it cannot be verified that it is dry in those inaccessible locations; and therefore, aging management actions are performed on those cables.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, XI.E3B, Element 1, "Program Description" is revised to state:

> The word 'potentially' is necessary to capture environmental unknowns associated with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring (i.e., a cable is assumed to be wet if it cannot be verified that it is dry in inaccessible locations; and therefore, aging management actions are performed on those cables). This ensures that inaccessible cables are conservatively scoped into the AMP and adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function.

Associated technical basis for the changes in the Program Description change are included in the Technical Bases Document, Supplement 1, Table 2-35, "GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," section XI.E3B.

NRC ID: 32-097, Andrew N. Mauer (NEI) - XI.E3C, "Electrical Insulation For Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," deletion the word "potentially" in relation to cables exposed to significant moisture and deletion of the phrase "multiple random," in relation to failures of the cable insulation systems; correction of "low voltage" to allow for testing on other cable types in-lieu of low-voltage power cable direct-testing if all the other listed caveats are met.

Overview of Public Comment:

The comment recommends for the NRC staff to delete the word "potentially" in relation to cable exposed to significant moisture and the phrase "multiple random," in relation to failures of the cable insulation systems, and correct "low voltage" to allow for testing on other cable types in-lieu of low-voltage power cable direct-testing if all the other listed caveats are met in XI.E3C, "Electrical Insulation For Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Response:

The staff partially agrees with the comment. The staff disagrees with deleting the word "potentially" because in the context of the areas identified by the comment it is necessary to capture environmental unknowns associated with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring. This ensures that inaccessible cables are conservatively scoped into the AMP and adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function. Using this term in this context is consistent with EPRI aging management implementation guidance in 3002010641 (low voltage cables) and 3002000557 (medium voltage cables) as these EPRI reports assume a cable to be wet if it cannot be verified that it is dry in those inaccessible locations; and therefore, aging management actions are performed on those cables.

The staff agrees with deleting the phrase "multiple random," in relation to failures of the cable insulation systems. The staff clarifies low voltage power cables testing to allow for testing on other cable types in-lieu of low-voltage power cable direct-testing if all the other listed caveats are met in XI.E3C, because these changes will ensure that in-scope low-voltage power cables not subject to 10 CFR 50.49 environmental qualification requirements are maintained consistent with the current licensing basis through the subsequent period of extended operation.

Overview of Proposed Changes:

In GALL-SLR Report, Volume 2, Revision 1, XI.E3C, Element 1, "Program Description" is revised to state:

> The word 'potentially' is necessary to capture environmental unknowns associated with inaccessible cables. If cables could be exposed to significant moisture (based on location and geology) they should be included in the program and therefore subject to increased monitoring (i.e., a cable is assumed to be wet if it cannot be verified that it is dry in inaccessible locations; and therefore, aging management actions are performed on those cables). This ensures that inaccessible cables are conservatively scoped into the AMP and

> adequately monitored to provide reasonable assurance that cables potentially exposed to wetting or submergence (i.e., significant moisture) can perform their intended function.

The "Program Description" is further revised to state:

> 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 failures of the cable insulation system, and compromise system defense-in-depth.

In addition, the "Program Description" is further revised. This program description was also revised in response to another comment. The final version states:

> Testing of installed inservice inaccessible and underground low voltage power cables as part of an existing maintenance, calibration or surveillance program (that can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope inaccessible instrument and control cables) as well as testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power or instrument and control 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.

Associated technical basis for the changes in the Program Description changes are included in the Technical Bases Document, Supplement 1, Table 2-35, "GALL-SLR Report, Revision 1, Chapter XI, Electrical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.E3C.

NRC ID: 32-098, Andrew N. Mauer (NEI) - Additional AMR rows similar to VII.C1.A-409 to allow AMPs (i.e., XI.M20, XI.M27, XI.M38) to manage wall thinning due to erosion for non-FAC systems.

Overview of Public Comment:

The comment requests that AMR items similar to VII.C1.A-409 be added to allow other aging management programs (i.e., XI.M20, XI.M27, XI.M38) to manage wall thinning due to erosion for non-flow-accelerated corrosion (FAC) systems because many applicants credit other aging management programs to manage erosion in non-FAC systems.

Response:

The staff disagrees with the comment proposals. While the staff agrees that applicants often credit other aging management programs to manage erosion in non-FAC systems, the staff does not agree that additional AMR items should be added to license renewal guidance documents to address this issue. The above cited AMR item was introduced through LR-ISG-2012-01 (ADAMS Accession No. ML12352A057) because the staff continued to encounter aging management programs for FAC (i.e., XI.M17) that were also being used to manage wall thinning due to erosion mechanisms. As currently noted in XI.M17, the FAC program may be used to manage wall thinning due to erosion that is not being managed

by another program. To limit the continued expansion of the AMR items, the staff notes that applicants can cite a generic Note E for item VII.C1.A-409 to manage wall thinning due to erosion using another aging management program, which would still be considered consistent with license renewal guidance.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-099, Andrew N. Mauer (NEI) - Reference to inspections "similar to" ASME Code Examinations VT-1 and VT-3, as to not imply that all the related requirements of the ASME Code are followed.

Overview of Public Comment:

The commenter recommends that reference to VT-1 and VT-3 inspections for non-ASME Code components should refer to inspections "similar to" VT-1 and VT-3. The commenter argues that VT-1 and VT-3 examinations are ASME Code Examinations and, therefore, reference to VT-1 and VT-3 implies all the related requirements of the ASME Code are to be followed. The commenter adds that implementation of this recommendation is difficult because the site procedures for VT-1 and VT-3 adhere to Code inspection requirements that do not apply to non-Code components.

Response:

The staff agrees with this comment. GALL-SLR Report AMPs XI.M36, "External Surfaces Monitoring Of Mechanical Components," and XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping And Ducting Components," are revised to clarify that VT-1 inspections are optional for non-ASME Code components. VT-1 and VT-3 inspections are referenced in AMP XI.M32; however, they are preceded by "e.g.," (for example). Therefore, changes to AMP XI.M32 are not necessary.

Overview of Proposed Changes:

Revised GALL-SLR Report, Volume 2, Revision 1, AMPs XI.M36 and XI.M38, item 4, "Detection of Aging Effects" in each AMP, to clarify that VT-1 inspections are optional for non-ASME Code components.

Associated technical basis for the Detection of Aging Effects changes are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," sections XI.M36, "External Surfaces Monitoring Of Mechanical Components," and XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping And Ducting Components."

NRC ID: 32-100, Andrew N. Mauer (NEI) - Simplification of GALL-SLR AMR lines to consolidate all similar air environments such as Air-Indoor Uncontrolled, Air-Outdoor, and Condensation.

Overview of Public Comment:

The comment requests that GALL-SLR AMR lines be simplified to consolidate all similar air environments. Previous versions of GALL guidance made a distinction between environments such as Air-Indoor Uncontrolled, Air-Outdoor, and Condensation since different aging effects were predicted in these different environments. For example, no aging effects were predicted for various materials such as stainless steel, aluminum, copper alloy, and galvanized steel in an Air-Indoor Uncontrolled environment while aging was predicted for Air-Outdoor and Condensation environments. The NRC now assumes the presence of contaminants resulting in age-related degradation in all air environments. The better approach would be to go back to the more realistic aging predictions used in previous versions of the GALL given the lack of operating experience indicating any significant aging issues in Air-Indoor environments for non-steel metallic materials.

However, if the NRC does not intend to revert back to the aging predictions used in previous versions of the GALL, then the various similar air environments should be consolidated for simplicity.

Response:

The staff disagrees with the comment. Based on a review of the GALL-SLR Report (Initial Report) the Technical Bases Document (Initial Report), and the Disposition of Public Comments on the Draft SLR Guidance (NUREG-2222 [Initial Report]) it appears that the commenter may not have realized a change made between the GALL and the GALL-SLR has already incorporated the requested change.

The NRC Staff reviewed the GALL-SLR Report (NUREG-2191) Volume 2, Revision 1, Table IX.D, “Use of Terms for Environments.” The table contains specific definitions for Air, Air-dry, Air-Indoor controlled, Air-Indoor uncontrolled, Air-outdoor, and Air with borated water leakage. As noted in Table XI.D, the term “air” was added to allow AMR items to be more succinct because the term “air” reduces the number of cited terms for some AMR items where for the material, the aging effect can occur regardless of the particular air environment.

In NUREG-2222 (Initial Report), the NRC staff’s response to comment 066 discussed how it was appropriate for the term “air” to replace the terms “air-indoor uncontrolled” and “air-outdoor” because the Fire Water System AMP recommended internal and external inspections, regardless of the type of air to which the tank was exposed.

In addition, the basis for inclusion of the term “air” was discussed in the Technical Bases Document (Initial Report), and was further explained in the “GALL-SLR Report, Revision 1, and SRP-SLR Supplemental Staff Guidance” document issued on March 29, 2016 (ADAMS Accession No. ML16041A090), which clarified how use of the term “air” was also appropriate for the changes made to the Further Evaluation sections of the SRP-SLR, Revision 1, AMP XI.M29, “Aboveground Metallic Tanks,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” and AMR line items to address cracking and loss of material for aluminum and stainless steel components. In summary, the GALL-SLR (initial report) added the term “air” to allow consolidation of different air environments when a material is susceptible

to aging, regardless of the specific type of air environment to which it is exposed. The previously used specific air environments (e.g., air-indoor controlled, air-indoor uncontrolled) were retained for those specific instances where their use was needed.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-101, Andrew N. Mauer (NEI) - Deletion of "Long-term loss of material due to general corrosion" from GALL-SLR AMR lines, associated SRP-SLR lines, and applicable AMPs; general corrosion is a slow-acting long-term aging effect that is adequately addressed through the normal "loss of material" AMR lines and is adequately managed through existing AMPs without any specific guidance.

Overview of Public Comment:

The comment requests removal of "Long-term loss of material due to general corrosion" from GALL-SLR AMR line items, associated SRP-SLR line items, and applicable AMPs. The commentor noted that general corrosion is a slow-acting long-term aging effect that is adequately addressed through the normal "loss of material" AMR line items and is adequately managed through existing AMPs without any specific guidance. Further, the distinction between "Long-term loss of material due to general corrosion" and "Loss of material due to general corrosion" is not clear.

Response:

The staff disagrees with the commentor's position. As noted in Table IX.E of the GALL-SLR Volume 2, Revision 1, 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. Therefore, the NRC has concluded that "long-term loss of material due to general corrosion" is not adequately addressed through the "loss of material" AMR line items.

AMP XI.M32 of the GALL-SLR Volume 2, states "Long-term loss of material due to general corrosion for 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 on 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."

From AMP XI.M32 of the GALL-SLR Volume 2, 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.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-102, Andrew N. Mauer (NEI) - Elimination of further evaluation SRP-SLR sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6 addressing recurring internal corrosion.

Overview of Public Comment:

The comment requests the elimination of further evaluation sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6 addressing recurring internal corrosion, because OE Feedback Reports (NUREG-1275) document these issues and similar known/well-understood aging issues, meaning they are unnecessary since GALL-SLR, Revision 1 and the SRP-SLR, Revision 1, already address these issues. The comment contends that local corrosion issues occurring in multiple discrete locations in a raw water system is not a recurring issue but rather a well-known and expected degradation mechanism presenting in different locations due to the similar materials and environmental stressors, and the guidance is overly conservative.

Response:

NRC staff disagrees that further evaluation should be eliminated for corrosion events that recur at levels equaling or exceeding the following recurrence threshold, which is defined in the SRP-SLR:

- Three or more refueling outage cycles in a 10-year search, or
- Two or more refueling outage cycles in a 5-year search and component not meeting acceptance criteria or reduction in wall thickness greater than 50 percent.

The SRP-SLR provides an acceptable way to augment AMP inspections when corrosion occurs at levels beyond a predetermined threshold. It is especially serious for a component not to meet criteria (b) above, since that indicates either especially fast progressing corrosion or a component not meeting its intended function. It would be nonconservative to eliminate the current SRP-SLR guidance under those conditions.

Applicants commonly identify and document instances of recurring internal corrosion of various components and systems exposed to various water environments including raw water, treated water, and waste water during their applications for license renewal and subsequent license

renewal. In at least one license renewal application and one subsequent license renewal application, the applicants initially stated recurring internal corrosion was not applicable to a given system, however, following the staff's review of plant-specific operating experience, and discussions with the applicant, it was determined that recurring internal corrosion was applicable. Further evaluations specified by the SRP-SLR and performed by these applicants have resulted in component repair and replacements, mitigation of corrosive environments (for example, chemical treatments), and augmented inspections. This provides objective evidence of the necessity and effectiveness of the SRP-SLR guidance to manage recurring internal corrosion.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-103, Andrew N. Mauer (NEI) - SRP-SLR Section 3.5.2.2.2.8, clarify the NRC's intent with respect to justification for the use of NUREG-1509 generic nil-ductility temperature values in lieu of those from plant-specific materials testing data.

Overview of Public Comment:

The comment proposes that the NRC clarify intent with respect to justification for the use of NUREG-1509 generic nil-ductility temperature values in lieu of those from plant-specific materials testing data.

Response:

The staff agrees with the comment. The staff clarifies the use NUREG-1509 generic nil-ductility temperature values by adding specificity as to when the generic values may be used as described in SRP-SLR Section 3.5.2.2.2.8.

Overview of Proposed Changes:

The staff clarifies that if the initial nil-ductility transition temperature (NDTT) values of the plant-specific support materials are available, then the plant-specific values should be used. If plant-specific initial NDTT values are not available, and if the plant-specific support material is one of the types/grades of steels in Table 4-2 of NUREG-1509, the generic initial NDTT values in Table 4-1 of NUREG-1509 may be used with 1.3 times the standard deviation. If plant-specific initial NDTT values are not available, and if the plant-specific support material is not one of the types/grades of steels in Table 4-2 of NUREG-1509, the generic initial NDTT values in Table 4-1 of NUREG-1509 with 1.3 times the standard deviation may be used provided that justification is included (e.g., chemical composition, mechanical properties, manufacturing process, fracture toughness, initial NDTT values from published sources) that demonstrates the plant-specific support material is similar to the corresponding type/grade of steel in Table 4-2 of NUREG-1509.

NRC ID: 32-104, Andrew N. Mauer (NEI) - SRP-SLR Section 3.5.2.2.2.8, change of the threshold value at which neutron damage could be a concern per NUREG-1509 Figure 3-1, and conservative screening for effect of embrittlement being more appropriate.

Overview of Public Comment:

The comment is regarding Draft NUREG-2192 (SRP-SLR), Revision 1 (ML23180A191), Sections 3.5.2.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete," and 3.5.3.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete." The comment proposes to change the threshold value at which neutron damage could be a concern from 2×10^{-5} dpa to 10^{-4} dpa. NUREG-1509 Figure 3-1 shows no measured data below 10^{-4} dpa (equivalent to 1×10^{-4} dpa) and the upper-bound curve was drawn with an arbitrary zero embrittlement shift at 10^{-5} dpa.

Response:

The staff agrees with the comment because below 1×10^{-4} dpa, embrittlement shift due to neutron irradiation is insignificant for RV steel structural supports.

Overview of Proposed Changes:

In SRP-SLR (NUREG 2192) Revision 1, Sections 3.5.2.2.2.8 and 3.5.3.2.2.8, the threshold value at which neutron damage could be a concern is changed from a value of 2×10^{-5} dpa to a value of 1×10^{-4} dpa.

The Technical Bases Document, Supp. 1, Table 3-7, "SRP-SLR, Revision 1, Chapter 3.5, Containments, Structures, and Component Supports, Differences from SRP-SLR, Revision 0, and Their Technical Bases," is revised to reflect the changes.

NRC ID: 32-105, Andrew N. Mauer (NEI) - SRP-SLR Section 3.5.2.2.2.8, deletion of text correlating alloying elements with embrittlement of reactor pressure vessel support steels.

Overview of Public Comment:

The comment proposes deletion of text correlating alloying elements with embrittlement of reactor pressure vessel support steels in SRP-SLR, Revision 1, Section 3.5.2.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete," because it claims that there is no information correlating alloying elements with embrittlement of reactor pressure vessel support steels.

Response:

The staff does not agree with the comment. The comment cites a paper as the basis for its claim that there is no information correlating alloying elements with embrittlement of reactor

pressure vessel support steels. The cited paper described a study performed on the potential impact of copper, an alloying element, on the embrittlement of A588 steel, a type of steel used for reactor pressure vessel supports. The cited paper concluded that the copper content of the A588 steel is not a factor with respect to embrittlement of the steel. However, a study of a single type of steel is not enough to draw a generic conclusion on the effects of alloying elements on embrittlement of reactor pressure vessel support steels because there are various types of steels used for reactor pressure vessel supports.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-106, Andrew N. Mauer (NEI) - SRP-SLR Section 3.5.2.2.2.8, revision of the further evaluation section to focus only on embrittlement rather than on "combined effects of aging."

Overview of Public Comment:

For Draft SRP-SLR (NUREG-2192), Revision 1, 3.5.2.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete," and 3.5.3.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete," the comment proposes to focus only on embrittlement rather than on "combined effects of aging." Other aging effects are adequately managed by existing aging management programs in GALL-SLR such that these aging effects do not need to be combined in this further evaluation.

Response:

The staff does not agree with the comment. Sections 3.5.2.2.2.8 and 3.5.3.2.2.8 of Draft SRP-SLR Revision 1, states "combined effects of aging associated with irradiation," and not simply "combined effects of aging." While embrittlement of steel due to irradiation is the primary aging effect of this subject SRP-SLR further evaluation, it is not the only one. Irradiation can also cause loss of intended function of other components and/or materials in the reactor vessel steel supports, e.g., degradation of lubricants in sliding surfaces due to irradiation, that can lead to loss of mechanical function of the sliding surfaces. Thus, Sections 3.5.2.2.2.8 and 3.5.3.2.2.8 state "combined effects of aging associated with irradiation," and not simply "combined effects of aging."

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-107, Andrew N. Mauer (NEI) - SRP-SLR Section 3.5.2.2.2.8, revise the further evaluation to exclude skirt supported reactors.

Overview of Public Comment:

The comment proposes to revise the further evaluation associated with Draft SRP-SLR (NUREG-2192), Revision 1, Sections 3.5.2.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete," and 3.5.3.2.2.8, "Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete," to exclude skirt-supported reactors. The comment states that, as discussed in NUREG-1509, skirt-supported reactor supports would not experience high exposure to irradiation such that embrittlement would not be a concern for this design.

Response:

The staff does not agree with the comment. The skirt-supported reactor pressure vessel design is included in the further evaluation associated with Draft NUREG-2192, Revision 1, Sections 3.5.2.2.2.8 and 3.5.3.2.2.8, because plant-specific information is needed to confirm or demonstrate that exposure to irradiation at the skirt is at a level that embrittlement would not be a concern. The statement in NUREG-1509 about skirt-supported reactor pressure vessel design not experiencing high irradiation exposure is a generic statement, and therefore, is not plant-specific information.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-108, Andrew N. Mauer (NEI) - SRP-SLR Section 4.7.4.1, "Leak-before-break Analysis," Section 4.7.4.1, rephrase item (v).

Overview of Public Comment:

The comment recommends that item (v) in the final sentence of the third paragraph in draft SRP-SLR, Revision 1, Section 4.7.4.1 be rephrased to say, "critical locations for LBB evaluation" in place of the current phrasing, "locations of critical cracks." The current phrasing implies the existence of cracks in critical locations. The recommended terminology more broadly addresses the locations of interest.

Response:

The staff agrees with the comment. The staff notes that the current wording, "locations of critical cracks," is not inconsistent with the wording, "critical crack sizes," as used in Ref. [1], in terms of the usage of the word, "crack," in the context of the leak-before-break (LBB) analysis. However, the staff agrees that the suggested wording, "critical locations for LBB evaluation," may more broadly address the locations of interest in the LBB analysis.

Overview of Proposed Changes:

SRP-SLR, Revision 1, Section 4.7.4.1, "Leak-before-break Analysis," Item (v), will be changed from "locations of critical cracks" to "critical locations for LBB evaluation."

NRC ID: 32-109, Andrew N. Mauer (NEI) - SRP-SLR Section 4.7.4.1, "Leak-before-break Analysis," Section 4.7.4.1, deletion of item (ii).

Overview of Public Comment:

The comment recommends deletion of item (ii) in the final sentence of the fourth paragraph in draft SRP-SLR, Revision 1, Section 4.7.4.1 (i.e., "and (ii) fatigue transient cycles and crack sizes"). This phrase could imply that fatigue crack growth analysis should be performed. However, the fatigue crack growth analysis is not necessary per Ref. [1].

Response:

The staff agrees, and notes that Ref. [1] indicates that the final rule regarding the leak-before-break (LBB) analysis does not require a fatigue crack growth analysis. The staff also notes that some of the initial and subsequent license renewal applications include a fatigue crack growth analysis as part of the leak-before-break time-limited aging analysis (LBB TLAA) to demonstrate that the aging effect of fatigue crack growth does not affect the conclusion of the LBB analysis (e.g., Ref. [2], [3] and [4]). Considering that the existing LBB analysis may or may not include a fatigue crack growth analysis, the staff deleted item (ii) from the examples for the time-dependent aspect of the LBB analysis.

Overview of Proposed Changes:

SRP-SLR, Revision 1, Section 4.7.4.1, Item (ii) in the final sentence of the fourth paragraph in draft has been deleted. Staff also made minor editorial changes to the sentence to account for that deletion:

> An example of the time-dependent parameters and the associated analysis in the LBB TLAA is the fracture toughness of cast austenitic stainless steel (CASS) piping materials due to thermal aging effect.

The following references were added to SRP-SLR, Revision 1, Section 4.7.4.1, "Leak-before-break Analysis:"

NRC, 10 CFR 50, Modification of General Design Criteria 4 Requirements for Protection Against Dynamic Effects of Postulated Pipe Ruptures, Final Rule, Federal Register/Volume 52, No. 207/Tuesday, October 27, 1987/Rules and Regulations, pp. 41288 - 41295 (52 FR 41288).

South Texas Project Units 1 and 2 License Renewal Application, Section 4.3.2.11, October 5, 2010, ADAMS Accession No. ML103010262.

Byron and Braidwood Stations Units 1 and 2 License Renewal Application, Section 4.7.1, June 3, 2013, ADAMS Accession No. ML13161A223.

Turkey Point Nuclear Plant Units 3 and 4 Subsequent License Renewal Application, Section 4.7.3, April 30, 2018, ADAMS Accession No. ML18113A146.

NRC ID: 32-110, Andrew N. Mauer (NEI) - SRP-SLR Section 4.7.4.2, "Pump Casing Flaw Tolerance Analysis," rephrase of text to add "crack growth" to improve clarity.

Overview of Public Comment:

The comment recommends rephrasing SRP-SLR, Revision 1, Section 4.7.4.2, "Pump Casing Flaw Tolerance Analysis" text in the parentheses from "fatigue transient cycles, and fatigue crack sizes" to "fatigue crack growth transient cycles, and fatigue crack growth crack sizes." The recommended wording improves clarity.

Response:

The staff agrees with the comment

Overview of Proposed Changes:

In SRP-SLR, Revision 1, Section 4.7.4.2, "Pump Casing Flaw Tolerance Analysis," the text in the parentheses in the final sentence of the second paragraph will be changed from "fatigue transient cycles, and fatigue crack sizes" to "fatigue crack growth transient cycles, and fatigue crack growth crack sizes."

NRC ID: 32-111, Andrew N. Mauer (NEI) - Table-2-29, "Chapter IX.E – Aging Effects, Differences From Chapter IX GALL-SLR Report, Revision 0, and Their Technical Base," the technical basis for the change to the cracking definition refers to Table-2-29 for the technical basis for the new proposed XI.M43 AMP, statement is made in Table 2-29, confirmation that this is reference should be to Table 2-33.

Overview of Public Comment:

The commenter states the following:

Part 1: In the draft Revision 1 of GALL-SLR, Table IX.E, the updated definition of Cracking attributes CFRP cracking to delamination or disbonding, caused primarily by installation issues, rather than aging.

Part 2: There's no evidence of age-related delamination or disbonding leading to CFRP cracking. Thus, cracking shouldn't be considered an aging effect for CFRP, and the second paragraph of the Cracking definition in Table IX.E should be removed.

Part 3: The change in the Cracking definition is linked to the technical basis provided in Table 2-29 for the proposed AMP XI.M43. It's likely referring to Table 2-33 instead of Table 2-29.

Response:

The staff disagrees with parts 1 and 2 of the comment, but agrees with part 3 of the comment.

Response to Parts 1 and 2: The staff notes that exposure to environmental effects such as temperature and/or moisture can cause degradation of epoxy resin matrix in CFRP composite. Degradation of matrix can result in cracking of fiber-matrix interfacial bonding, delamination of

layers, lowering matrix glass transition temperature, swelling of matrix, and microcracking of matrix [MIL-HDBK-17]. CFRP is brittle. As such, cracking may occur. Therefore, cracking can be caused by aging.

Operating experience (OE) exists on the failure of CFRP-repaired pipe specifically related to loss of material due to delamination, that causes flow blockage and can lead to cracking at a nuclear plant. Element 10 of AMP XI.M43 discusses this OE regarding failure of CFRP-repaired piping. The NRC staff has determined that this OE is proprietary.

Response to Part 3. The staff revised the Technical Bases Document, Supplement 1, Table 2-29, Loss of Material definition to refer to Table 2-33 instead of Table 2-29.

Overview of Proposed Changes:

In Technical Bases Document, Supplement 1., Table 2-29, line item “Loss of Material”, under the column “Technical Basis for Change,” the reference to Table 2-29 is changed to Table 2-33.

References:

MIL-HDBK-17, “Composite Materials Handbook, Volume 1. Polymer Matrix Composites Guidelines for Characterization of Structural Materials.” https://indico.fnal.gov/event/13241/contributions/18146/attachments/12002/15271/MIL_Handbook_17.pdf, June 17, 2002

NRC ID: 32-112, Andrew N. Mauer (NEI) - Table-2-29, “Chapter IX.E – Aging Effects, Differences From Chapter IX GALL-SLR Report, Revision 0, and Their Technical Base,” the technical basis for the change to the Flow Blockage definition refers to Table-2-29 for the technical basis for the new proposed XI.M43 AMP, statement is made in Table 2-29, confirmation that this is reference should be to Table 2-33.

Overview of Public Comment:

The comment states the following:

Part 1: Delamination or disbonding of CFRP is caused by improper installation/quality control and is not caused by aging. Does operating experience exist indicating age-related delamination or disbonding of CFRP resulting in flow blockage? If not, Flow Blockage should be removed as an applicable aging effect for CFRP and reference to delamination or disbonding of CFRP should be removed from the Flow Blockage definition in draft Revision 1 of GALL-SLR, Table IX.E. One of the benefits of installing HDPE and CFRP is improved flow rates and resistance to flow blockage due to fouling.

Part 2: The technical basis for the change to the Flow Blockage definition refers to Table-2-29 for the technical basis for the new proposed XI.M43 AMP. It is suspected the staff meant to refer to Table 2-33?

Response:

The staff disagrees with part 1 of the comment, but agrees with part 2 of the comment.

Response to Part 1: The staff notes that exposure to environmental effects such as temperature and/or moisture can cause degradation of epoxy resin matrix in CFRP composite. Degradation of matrix can result in cracking of fiber-matrix interfacial bonding, delamination of layers, lowering matrix glass transition temperature, swelling of matrix, and microcracking of matrix [MIL-HDBK-17]. CFRP is brittle. As such, cracking may occur.

Flow blockage is an effect which can occur due to fouling and delamination and debonding of CFRP repaired piping. For CFRP-repaired pipe, flow blockage can occur due to delamination and debonding of the CFRP. As noted above, delamination and debonding can be caused by environmental effects, meaning they can be caused by aging. Element 10 of AMP XI.M43 describes an operating experience where a section of CFRP layers was completely missing from the pipe surface. The CFRP debris were found at the metallic screens (strainer) inside of the pipe.

The staff revised the Technical Bases Document, Supplement 1, Table 2-29, Loss of Material definition to refer to Table 2-33 instead of Table 2-29.

Overview of Proposed Changes:

In the Technical Bases Document, Supplement 1, Table 2-29, line item “Loss of Material”, under the column “Technical Basis for Change,” the reference to Table 2-29 is changed to Table 2-33.

References:

MIL-HDBK-17, “Composite Materials Handbook, Volume 1. Polymer Matrix Composites Guidelines for Characterization of Structural Materials.” https://indico.fnal.gov/event/13241/contributions/18146/attachments/12002/15271/MIL_Handbook_17.pdf, June 17, 2002

NRC ID: 32-113, Andrew N. Mauer (NEI) - Table-2-29, “Chapter IX.E – Aging Effects, Differences From Chapter IX GALL-SLR Report, Revision 0, and Their Technical Base,” the technical basis for the change to the Loss of Material definition refers to Table-2-29 for the technical basis for the new proposed XI.M43 AMP, statement is made in Table 2-29, confirmation that this is reference should be to Table 2-33.

Overview of Public Comment:

The comment states that the updated Loss of Material definition provided in draft GALL-SLR Report Revision 1 states that loss of material of CFRP can be caused by delamination or disbonding. Delamination or disbonding of CFRP is caused by improper installation/quality control and is not caused by aging. The commenter asks if operating experience (OE)exists, indicating age-related delamination or disbonding of CFRP resulting in loss of material. If not, the commenter recommends that the reference to delamination or disbonding of CFRP be removed from the Loss of Material definition.

The commenter adds that updated Loss of Material definition provided in draft GALL-SLR Report Revision 1 states that loss of material of CFRP can also be caused by environmental exposure (e.g., chemical attack, moisture). Degradation of polymeric materials, including HDPE and CFRP, due to environmental exposure does not occur if the correct material is selected for the modification (i.e., this is a design issue and not an aging issue). The commenter asks if OE exist indicating age-related delamination or disbonding of CFRP. If not, the commenter recommends that the reference to environmental exposure for polymeric materials be removed from the Loss of Material definition.

The commenter adds that the technical basis for the change to the Loss of Material definition refers to Table-2-29 for the technical basis for the new proposed XI.M43 AMP, and suspects that the statement should instead refer to Table 2-33.

Response:

The staff disagrees with the comment. For CFRP-repaired piping:

- Loss of material can occur from delamination and debonding of the CFRP layers. The delaminated and debonded layer(s) can get separated and peeled away from the laminate and cause reduction in flow rate or flow blockage.
- Flow blockage or reduction in flow rate can also occur from a dislodged expansion ring assembly.
- The CFRP is susceptible to environmental effects. Exposure of CFRP to temperature and/or moisture can cause degradation of epoxy resin matrix. Degradation of matrix will result in cracking of fiber-matrix interfacial bonding, delamination of layers, lowering matrix glass transition temperature, swelling of matrix, and microcracking of matrix [MIL-HDBK-17]. Therefore, degradation of matrix, delamination, and debonding of layer(s) followed by separation from the laminate can result in loss of materials and can lead to flow blockage.
- The staff is aware of one OE that was reported in 2021 by a licensee regarding the delamination failure of the CFRP-repaired pipe that resulted in complete loss of CFRP layer(s) and flow blockage. The NRC staff has determined that the details of the OE are proprietary.
- Improper materials and installation of CFRP not identified during fabrication inspections and quality assurance can cause delamination in the future.
- For HDPE, degradation or loss of materials due to environmental effects can occur if the incorrect material is selected, or if an improper fusion butt joint or electrofused joint is performed. HDPE is sensitive to high temperatures [ASME 2008-TN10987]. At high temperatures, HDPE will deform which could lead to loss of material and strength. HDPE fabrication can introduce moisture in the resin/hydrocarbon mixture which can cause degradation in the future [ASME 2008-TN10987].
- The staff notes that it is difficult to determine whether the degradation is caused by aging, improper installation, or a combination of both. The degradation in CFRP-repaired and HDPE piping needs to be monitored and managed.
- The NRC staff is aware of an OE related to the delamination and/or debonding of CFRP-repaired piping that caused flow blockage at nuclear plant.

- The staff determined that delamination and/or debonding of CFRP should not be removed for the loss of material definition. However, in the initial version of Technical Bases Document , within Table 2-29, under line item “Loss of Material”, under the column “Technical Basis for Change,” Table 2-29 was referenced. This is a typographic error and Table 2-33 should have been referenced instead of Table 2-29.

Overview of Proposed Changes:

In the Technical Bases Document, Supplement 1, within Table 2-29, under line item “Loss of Material,” under the column “Technical Basis for Change,” the staff will reference Table 2-33 instead of Table 2-29.

References:

MIL-HDBK-17, “Composite Materials Handbook, Volume 1. Polymer Matrix Composites Guidelines for Characterization of Structural Materials.” https://indico.fnal.gov/event/13241/contributions/18146/attachments/12002/15271/MIL_Handbook_17.pdf, June 17, 2002. DOD 2002-TN10078

PVP2008-61906, “Tensile Testing and Material Property Development of High Density Polyethylene Pipe Materials” https://doi.org/10.1115/PVP2008-61906, July 24, 2009. ASME 2008-TN10987

NRC ID: 32-114, Andrew N. Mauer (NEI) – Technical Basis for XI.M17, “Flow Accelerated Corrosion,” states that the NRC is clarifying that commitments made in response to GL 89-08 were for an ongoing FAC program; while it is expected that the majority of stations made ongoing programmatic commitments in response to GL 89-08, no changes made to the GALL-SLR guidance would retroactively change the plant-specific commitments made in the responses to GL 89-08.

Overview of Public Comment:

The comment associated with the Technical Bases Document, (ADAMS Accession Nos. ML23291A071) takes issue with the fact that the change basis statement for the AMP XI.M17, “Flow Accelerated Corrosion,” Program Description, regarding the staff views that commitments in response to NRC Generic Letter (GL) 89-08 are for an ongoing flow-accelerated corrosion (FAC) program. The comment noted that any changes made to the GALL-SLR guidance would not retroactively change the plant-specific commitments made in response to GL 89-08. The comment further noted that if the NRC requires a commitment for an ongoing FAC program, separate from any commitments made through Part 54, then that should be addressed as a Part 50 issue.

Response:

The staff agrees, in part, with the comment that changes made to the GALL-SLR guidance would not retroactively change any plant-specific commitments made in response to GL 89-08. The staff notes that the comment did not take issue with the change to the program description itself (which inserted “for an ongoing monitoring program” into the sentence about licensee’s commitments made in response to GL 89-08), but instead questioned the basis for the change.

The clarification added to the XI.M17 specifically pertained to the request made in NRC GL 8908, regarding whether licensees had implemented “a long-term erosion-corrosion [i.e., FAC] monitoring program.” The staff’s clarification was not intended to question any licensees’ previous commitments. The technical basis document statement was intended to show that, for license renewal, the staff considered a “long-term” FAC monitoring program to be the same as an “ongoing” FAC program. The distinction being drawn between a one-time commitment to implement a long-term FAC program or an ongoing commitment to implement a FAC program appears to be a technicality. Either commitment results in a FAC program that would remain in effect and becomes part of the current licensing basis as provided in 10 CFR 54.3.

That the program, in response to GL 89-08, became part of the current licensing basis is supported in NUREG-1412, “Foundation for the Adequacy of the Licensing Bases.” NUREG-1412 discusses how the regulatory process has evolved in areas of major safety concerns and provides specific examples of how the current licensing basis for the various system types has changed over the years. For steam and power conversion systems, Section 10.3 “Evolution of the Current Licensing Basis,” discussed the need for issuance of GL 89-08, requesting licensees to implement a continuous monitoring program to detect unacceptable pipe wall thinning and to certify that the program was in place. Whether a plant’s commitments were or were not viewed as ongoing, as discussed in NUREG-1412, the NRC staff considered the program implemented in response to GL 89-08 as a long-term program that would remain in effect and thereby become part of a plant’s current licensing basis, as provided in 10 CFR 54.3.

Overview of Proposed Changes:

Not applicable.

NRC ID: 32-116, Andrew N. Mauer (NEI) - XI.M43, “HDPE Piping and CFRP Repaired Piping,” no adequate technical basis is provided for the new proposed AMP XI.M43.

Overview of Public Comment:

The comment states that the newly proposed AMP XI.M43 doesn't provide adequate technical justification. While it aims to manage age-related degradation in HDPE piping and CFRP repaired piping, it fails to provide a clear technical basis for its necessity. The Technical Bases Document, Supplement 1, mentions "unique aging issues" for HDPE and CFRP but doesn't elaborate on these issues or provide evidence of how they could affect the structures' performance during extended operation.

Response:

The staff agrees with the comment and will enhance the technical justification. The staff established AMP XI.M43 to monitor the CFRP repaired pipe and HDPE pipe for materials degradation, cracking, loss of materials, leakage, loss of structural integrity, flow blockage, and/or fouling. These problems may result from improper installation, or many years of inservice operation, or a combination of both. The technical basis for AMP XI.M43 is that the CFRP repaired pipe and HDPE pipe will likely encounter material degradation such as cracking, loss of materials, leakage, etc. The CFRP layers in the repaired pipe may develop debonding or delamination. The HDPE pipe may develop cracking. Therefore, AMP XI.M43 monitors these

pipes periodically to ensure their structural integrity. Table 2-33 of NUREG-2221, Supplement 1, provides additional information on technical basis.

Overview of Proposed Changes:

The GALL-SLR Report, Volume 2, Revision 1, XI.M43, "Program Description," is revised to read:

> This aging management program (AMP) manages the aging of the internal and external surfaces of buried, underground, safety-related, and in-scope non-safety-related high-density polyethylene (HDPE) piping and carbon fiber-reinforced polymer (CFRP)-repaired piping. The CFRP-repaired piping is defined in this AMP as application of CFRP on the internal surface of metal pipe as structural lining. This program manages aging through preventive, mitigative, inspection, and performance monitoring activities. It manages aging effects such as loss of material, cracking, delamination, debonding, and/or blistering. Aging effects can lead to loss of leak tightness, loss of strength, loss of modulus, debris, reduction in flow, and/or flow blockage.

Associated technical basis for the Program Description change are included in the Technical Bases Document Supplement 1, Table 2-33, "GALL-SLR Report, Revision 1, Differences from Chapter XI, Mechanical Aging Management Programs, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases," Section XI.M43.

NRC ID: 33, Richard T. McCarty Nuclear Utility Group on Equipment Qualification (NUGEQ), comments related to (1) clarifying that electrical and mechanical components required to meet 10 CFR 50.49 may contain age-sensitive items such as gaskets, seals, O-rings, etc. and (2) revising the definition of "Significant Aging Mechanisms."

Overview of Public Comment:

The comment relates to X.E1, "Environmental Qualification of Electric Equipment," and suggests revising X.E1 to clarify that 10 CFR 50.49 addresses electrical and mechanical components that are relied upon to ensure the functional capability of the equipment being qualified under the postulated design basis conditions and that mechanical components can include age-sensitive items such as gaskets, seals, or O-rings.

The comment also proposes to revise GALL-SLR Report Section IX.F, "Significant Aging Mechanisms," to align the definition of this term with that used by the Institute of Electrical and Electronics Engineers (IEEE). The comment stated that the GALL-SLR definition "…does not distinguish between non-critical functionality with safety-related or important to safety functionality."

Response:

This comment from NUGEQ was received on December 1, 2023, which is after the close of the public comment period. The NRC staff decided to admit the comment for consideration in order to maximize responsiveness to the public. It was practical for the staff to respond to this comment as the staff was still well within in the process of developing public comment

responses, and doing so did not require any significant additional resources or impact to the guidance update schedule.

The staff agrees with the comment to revise X.E1 and implemented all recommended changes in the comment related to that aging management program.

The staff, however, does not agree with the proposal to change the IX.F definition of “significant aging mechanisms” in the GALL-SLR Report, as it is inconsistent with aspects of the license renewal rule and guidance. The staff notes that the proposed definition includes the consideration of “abnormal service conditions.” Per SRP-SLR Section A.1.2.1, when identifying applicable aging effects, only the impact of normal plant operation needs to be considered. Abnormal service conditions need not be postulated, although the implications of a specific event that has occurred at a plant should be considered. In addition, the comment proposes to define the significance of an aging mechanism as it pertains to “important to safety” functions. The staff notes that the scope of systems, structures and components addressed by the license renewal rule is explicitly defined in 10 CFR 54.4, and that the rule does not use the “important to safety” terminology that appears in other regulations (such as 50.49). As a result, the use of this term in other regulatory contexts has the potential to introduce confusion into the functions within the license renewal scope. Finally, the staff notes that the license renewal rule requires only the management of the “effects” of aging, and thus the GALL-SLR Report deliberately defines the significance of an aging mechanism in the context of its potential to result in aging effects that produce a loss of intended function. The comment’s proposal removes this specific link to aging effects.

Overview of Proposed Changes:

The GALL-SLR Report, Volume 2, Revision 1, X.E1, “Program Description,” is revised to include:

Qualification under § 50.49 addresses the electrical and mechanical components that are relied upon to ensure the functional capability of the equipment being qualified under the postulated design basis conditions. The mechanical components can include age sensitive items such as gaskets, seals, or O-rings.

Associated technical basis for the Program Description change is included in the Technical Bases Document Supplement 1, Table 2-32, “GALL-SLR Report, Revision 1, Chapter X, Time-Limited Aging Analysis, Differences From GALL-SLR Report, Revision 0, and Their Technical Bases,” section X.E1, “Environmental Qualification of Electric Equipment.”

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When finalized, this report will supersede NUREG-2191, Vol. 1 (Rev. 0)

11. ABSTRACT (200 words or less)

NUREG-2191, Vol. 1, Revision 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). 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 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 NUREG-2221, Supplement 1, "Technical Bases for Changes in the Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG–2192" (Technical Basis Document).

12. KEY WORDS/DESCRIPTORS (List words or phrases that will assist researchers in locating the report.)

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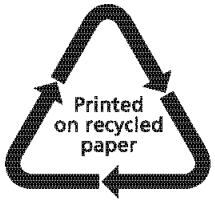

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