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

NUREG-2191, Vol. 2

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

Draft Report for Comment

Office of Nuclear Reactor Regulation

AVAILABILITY OF REFERENCE MATERIALS IN NRC PUBLICATIONS

NRC Reference Material

As of November 1999, you may electronically access NUREG-series publications and other NRC records at NRC's Library at www.nrc.gov/reading-rm.html. Publicly released records include, to name a few, NUREG-series publications; *Federal Register* notices; applicant, licensee, and vendor documents and correspondence; NRC correspondence and internal memoranda; bulletins and information notices; inspection and investigative reports; licensee event reports; and Commission papers and their attachments.

NRC publications in the NUREG series, NRC regulations, and Title 10, "Energy," in the *Code of Federal Regulations* may also be purchased from one of these two sources.

1. **The Superintendent of Documents**
   U.S. Government Publishing Office
   Mail Stop IDCC
   Washington, DC 20402-0001
   Internet: bookstore.gpo.gov
   Telephone: (202) 512-1800
   Fax: (202) 512-2104

2. **The National Technical Information Service**
   5301 Shawnee Rd., Alexandria, VA 22312-0002
   www.ntis.gov
   1-800-553-6847 or, locally, (703) 605-6000

A single copy of each NRC draft report for comment is available free, to the extent of supply, upon written request as follows:

Address: **U.S. Nuclear Regulatory Commission**
Office of Administration
Publications Branch
Washington, DC 20555-0001
E-mail: distribution.resource@nrc.gov
Facsimile: (301) 415-2289

Some publications in the NUREG series that are posted at NRC's Web site address www.nrc.gov/reading-rm/doc-collections/nuregs are updated periodically and may differ from the last printed version. Although references to material found on a Web site bear the date the material was accessed, the material available on the date cited may subsequently be removed from the site.

Non-NRC Reference Material

Documents available from public and special technical libraries include all open literature items, such as books, journal articles, transactions, *Federal Register* notices, Federal and State legislation, and congressional reports. Such documents as theses, dissertations, foreign reports and translations, and non-NRC conference proceedings may be purchased from their sponsoring organization.

Copies of industry codes and standards used in a substantive manner in the NRC regulatory process are maintained at—

The NRC Technical Library
Two White Flint North
11545 Rockville Pike
Rockville, MD 20852-2738

These standards are available in the library for reference use by the public. Codes and standards are usually copyrighted and may be purchased from the originating organization or, if they are American National Standards, from—

American National Standards Institute
11 West 42nd Street
New York, NY 10036-8002
www.ansi.org
(212) 642-4900

Legally binding regulatory requirements are stated only in laws; NRC regulations; licenses, including technical specifications; or orders, not in NUREG-series publications. The views expressed in contractorprepared publications in this series are not necessarily those of the NRC.

The NUREG series comprises (1) technical and administrative reports and books prepared by the staff (NUREG–XXXX) or agency contractors (NUREG/CR–XXXX), (2) proceedings of conferences (NUREG/CP–XXXX), (3) reports resulting from international agreements (NUREG/IA–XXXX), (4) brochures (NUREG/BR–XXXX), and (5) compilations of legal decisions and orders of the Commission and Atomic and Safety Licensing Boards and of Directors' decisions under Section 2.206 of NRC's regulations (NUREG–0750).

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

NUREG-2191, Vol. 2

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

Draft Report for Comment

Manuscript Completed: October 2015
Date Published: December 2015

Office of Nuclear Reactor Regulation

COMMENTS ON DRAFT REPORT

Any interested party may submit comments on this report for consideration by the U.S. Nuclear Regulatory Commission (NRC) staff. Comments may be accompanied by additional relevant information or supporting data. Please specify the report number **NUREG–2191, Volume 1,** in your comments, and send them by the end of the comment period specified in the *Federal Register* notice announcing the availability of this report.

Addresses: You may submit comments by any one of the following methods. Please include Docket ID **NRC–2015–0251** in the subject line of your comments. Comments submitted in writing or in electronic form will be posted on the NRC website and on the Federal rulemaking website http://www.regulations.gov.

Federal Rulemaking Website: Go to http://www.regulations.gov and search for documents filed under Docket ID **NRC–2015–0251**. Address questions about NRC dockets to Carol Gallagher at 301-415-3463 or by e-mail at Carol.Gallagher@nrc.gov.

Mail comments to: Cindy Bladey, Chief, Rules, Announcements, and Directives Branch (RADB), Division of Administrative Services, Office of Administration, Mail Stop:

OWFN-12-H08, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001

For any questions about the material in this report, please contact: Bennett Brady, Senior Project Manager, 301-415-2981 or by e-mail at Bennett.Brady@nrc.gov.

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

ABSTRACT

The U.S. Nuclear Regulatory Commission (NRC) staff has defined subsequent license renewal (SLR) to be the period of extended operation from 60 years to 80 years of nuclear power plant operation. NUREG–2191, “Generic Aging Lessons Learned for Subsequent License Renewal Report,” provides guidance for SLR applicants. The Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report contains the 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 on 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 (OE) at the plant are bounded by the conditions and OE for which the GALL-SLR Report program was evaluated. If these bounding conditions are not met, it is incumbent on the applicant to address any additional aging effects and augment the AMPs for SLR. For AMPs that are based on the GALL-SLR Report, the NRC staff will review and verify whether the applicant’s AMPs are consistent with those described in the GALL-SLR Report, including applicable plant conditions and OE. The focus of the NRC staff’s review of an SLR application is on those AMPs that an applicant has enhanced to be consistent with the GALL-SLR Report, those 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. The information in the GALL-SLR Report has been incorporated into the NUREG–2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants,” as directed by the Commission, to improve the efficiency of the SLR process.

TABLE OF CONTENTS

Section Page

ABSTRACT ... iii
LIST OF TABLES ... xi
LIST OF CONTRIBUTORS ... xv
ABBREVIATIONS ... xix
INTRODUCTION ... xxv
BACKGROUND ... xxvii
OVERVIEW OF THE GENERIC AGING LESSONS LEARNED FOR SUBSEQUENT LICENSE RENEWAL REPORT EVALUATION PROCESS ... xxxi
APPLICATION OF THE GENERIC AGING LESSONS LEARNED FOR SUBSEQUENT LICENSE RENEWAL REPORT ... xxxv

I APPLICATION OF AMERICAN SOCIETY OF MECHANICAL ENGINEERS CODE ... **i-1**

II CONTAINMENT STRUCTURES ... **II-1**
II PRESSURIZED WATER REACTOR CONTAINMENTS ... II-2
A1 CONCRETE CONTAINMENTS (REINFORCED AND PRESTRESSED) ... II A1-1
A2 STEEL CONTAINMENTS ... II A2-1
A3 COMMON COMPONENTS ... II A3-1
II BOILING WATER REACTOR CONTAINMENTS ... II B-1
B1 MARK I CONTAINMENTS ... II B1-1
B2 MARK II CONTAINMENTS ... II B2-1
II MARK III CONTAINMENTS ... II B3
B3 MARK III CONTAINMENTS ... II B3-1
B4 COMMON COMPONENTS ... II B4-1

III STRUCTURES AND COMPONENT SUPPORTS ... **III-1**
III SAFETY-RELATED AND OTHER STRUCTURES ... III-3
A1 GROUP 1 STRUCTURES (BOILNG WATER REACTOR REACTOR BUILDING, PRESSURIZED WATER REACTOR SHIELD BUILDING, CONTROL ROOM/BUILDING) ... III A1-1
A2 GROUP 2 STRUCTURES (BOILNG WATER REACTOR REACTOR BUILDING WITH STEEL SUPERSTRUCTURE) ... III A2-1
A3 GROUP 3 STRUCTURES (AUXILIARY BUILDING, DIESEL GENERATOR BUILDING, RADWASTE BUILDING, TURBINE BUILDING, SWITCHGEAR ROOM, YARD STRUCTURES, SUCH AS AUXILIARY FEEDWATER PUMPHOUSE, UTILITY/PIPING TUNNELS, SECURITY/LIGHTING POLES, MANHOLES, DUCT BANKS; STATION BLACKOUT STRUCTURES, SUCH AS TRANSMISSION TOWERS, STARTUP TOWERS CIRCUIT BREAKER FOUNDATION, ELECTRICAL ENCLOSURE) ... III A3-1
A4 GROUP 4 STRUCTURES (CONTAINMENT INTERNAL STRUCTURES, EXCLUDING REFUELING CANAL) ... III A4-1
A5 GROUP 5 STRUCTURES (FUEL STORAGE FACILITY, REFUELING CANAL) ... III A5-1
A6 GROUP 6 STRUCTURES (WATER-CONTROL STRUCTURES) ... III A6-1
A7 GROUP 7 STRUCTURES (CONCRETE TANKS AND MISSILE BARRIERS) ... III A7-1

A8 GROUP 8 STRUCTURES (STEEL TANKS AND MISSILE BARRIERS) ... III A8-1
A9 GROUP 9 STRUCTURES (BOILNG WATER REACTOR UNIT VENT STACK) ... III A9-1
III COMPONENT SUPPORTS ... III-1
B1 SUPPORTS FOR ASME PIPING AND COMPONENTS ... III B1-1
B2 SUPPORTS FOR CABLE TRAYS, CONDUIT, HVAC DUCTS, TUBETRACK®, INSTRUMENT TUBING, NONASME PIPING AND COMPONENTS ... III B2-1
B3 ANCHORAGE OF RACKS, PANELS, CABINETS, AND ENCLOSURES FOR ELECTRICAL EQUIPMENT AND INSTRUMENTATION ... III B3-1
B4 SUPPORTS FOR EMERGENCY DIESEL GENERATOR, HEATING VENTILIATION, AND AIR CONDITIONING SYSTEM COMPONENTS, AND OTHER MISCELLANEOUS MECHANICAL EQUIPMENT ... III B4-1
B5 SUPPORTS FOR PLATFORMS, PIPE WHIP RESTRAINTS, JET IMPINGEMENT SHIELDS, MASONRY WALLS, AND OTHER MISCELLANEOUS STRUCTURES ... III B5-1

IV REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM ... IV-1
A1 REACTOR VESSEL (BOILING WATER REACTOR) ... IV A1-1
A2 REACTOR VESSEL (PRESSURIZED WATER REACTOR) ... IV A2-1
B1 REACTOR VESSEL INTERNALS (BOILING WATER REACTOR) ... IV B1-1
B2 REACTOR VESSEL INTERNALS (PRESSURIZED WATER REACTOR)—WESTINGHOUSE ... IV B2-1
B3 REACTOR VESSEL INTERNALS (PRESSURIZED WATER REACTOR)—COMBUSTION ENGINEERING ... IV B3-1
B4 REACTOR VESSEL INTERNALS (PRESSURIZED WATER REACTOR)—BABCOCK AND WILCOX ... IV B4-1
C1 REACTOR COOLANT PRESSURE BOUNDARY (BOILING WATER REACTOR) ... IV C1-1
C2 REACTOR COOLANT SYSTEM AND CONNECTED LINES (PRESSURIZED WATER REACTOR) ... IV C2-1
D1 STEAM GENERATOR (RECIRCULATING) ... IV D1-1
D2 STEAM GENERATOR (ONCE-THROUGH) ... IV D2-1
E COMMON MISCELLANEOUS MATERIAL/ ENVIRONMENT COMBINATIONS ... IV E-1

V ENGINEERED SAFETY FEATURES ... V-1
A CONTAINMENT SPRAY SYSTEM (PRESSURIZED WATER REACTORS) ... V A-1
B STANDBY GAS TREATMENT SYSTEM (BOILING WATER REACTORS) ... V B-1
C CONTAINMENT ISOLATION COMPONENTS ... V C-1
D1 EMERGENCY CORE COOLING SYSTEM (PRESSURIZED WATER REACTORS) ... V D1-1
D2 EMERGENCY CORE COOLING SYSTEM (BOILING WATER REACTORS) ... V D2-1
E EXTERNAL SURFACES OF COMPONENTS AND MISCELLANEOUS BOLTING ... V E-1
F COMMON MISCELLANEOUS MATERIAL/ ENVIRONMENT COMBINATIONS ... V F-1

VI ELECTRICAL COMPONENTS ... VI-1
A EQUIPMENT, NOT SUBJECT TO10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS ... VI A-1
B EQUIPMENT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS ... VI B-1

VII AUXILIARY SYSTEMS ... VII-1
A1 NEW FUEL STORAGE ... VII A1-1
A2 SPENT FUEL STORAGE ... VII A2-1
A3 SPENT FUEL POOL COOLING AND CLEANUP (PRESSURIZED WATER REACTOR) ... VII A3-1
A4 SPENT FUEL POOL COOLING AND CLEANUP (BOILING WATER REACTOR) ... VII A4-1
A5 SUPPRESSION POOL CLEANUP SYSTEM (BOILING WATER REACTOR) ... VII A5-1
B OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS ... VII B-1
C1 OPEN-CYCLE COOLING WATER SYSTEM (SERVICE WATER SYSTEM) ... VII C1-1
C2 CLOSED-CYCLE COOLING WATER SYSTEM ... VII C2-1
C3 ULTIMATE HEAT SINK ... VII C3-1
D COMPRESSED AIR SYSTEM ... VII D-1
E1 CHEMICAL AND VOLUME CONTROL SYSTEM (PRESSURIZED WATER REACTOR) ... VII E1-1
E2 STANDBY LIQUID CONTROL SYSTEM (BOILING WATER REACTOR) ... VII E2-1
E3 REACTOR WATER CLEANUP SYSTEM (BOILING WATER REACTOR) ... VII E3-1
E4 SHUTDOWN COOLING SYSTEM (OLDER BOILING WATER REACTOR) ... VII E4-1
E5 WASTE WATER SYSTEMS ... VII E5-1
F1 CONTROL ROOM AREA VENTILATION SYSTEM ... VII F1-1
F2 AUXILIARY AND RADWASTE AREA VENTILATION SYSTEM ... VII F2-1
F3 PRIMARY CONTAINMENT HEATING AND VENTILATION SYSTEM ... VII F3-1
F4 DIESEL GENERATOR BUILDING VENTILATION SYSTEM ... VII F4-1
G FIRE PROTECTION ... VII G-1
H1 DIESEL FUEL OIL SYSTEM ... VII H1-1
H2 EMERGENCY DIESEL GENERATOR SYSTEM ... VII H2-1
I EXTERNAL SURFACES OF COMPONENTS AND MISCELLANEOUS BOLTING ... VII I-1
J COMMON MISCELLANEOUS MATERIAL/ ENVIRONMENT COMBINATIONS ... VII J-1

VIII STEAM AND POWER CONVERSION SYSTEM ... VIII-1
A STEAM TURBINE SYSTEM ... VIII A-1
B1 MAIN STEAM SYSTEM (PRESSURIZED WATER REACTOR) ... VIII B1-1
B2 MAIN STEAM SYSTEM (BOILING WATER REACTOR) ... VIII B2-1
C EXTRACTION STEAM SYSTEM ... VIII C-1
D1 FEEDWATER SYSTEM (PRESSURIZED WATER REACTOR) ... VIII D1-1
D2 FEEDWATER SYSTEM (BOILING WATER REACTOR) ... VIII D2-1
E CONDENSATE SYSTEM ... VIII E-1

F STEAM GENERATOR BLOWDOWN SYSTEM (PRESSURIZED WATER REACTOR) .... VIII F-1
G AUXILIARY FEEDWATER SYSTEM (PRESSURIZED WATER REACTOR) .... VIII G-1
H EXTERNAL SURFACES OF COMPONENTS AND MISCELLANEOUS BOLTING .... VIII H-1
I COMMON MISCELLANEOUS MATERIAL/ ENVIRONMENT COMBINATIONS .... VIII I-1

IX USE OF TERMS FOR STRUCTURES, COMPONENTS, MATERIALS, ENVIRONMENTS, AGING EFFECTS, AND AGING MECHANISMS IX-1
A INTRODUCTION .... IX A-1
B STRUCTURES AND COMPONENTS .... IX B-1
C MATERIALS .... IX C-1
D ENVIRONMENTS .... IX D-1
E AGING EFFECTS .... IX E-1
F SIGNIFICANT AGING MECHANISMS .... IX F-1

X AGING MANAGEMENT PROGRAMS THAT MAY BE USED TO DEMONSTRATE ACCEPTABILITY OF TIME-LIMITED AGING ANALYSES IN ACCORDANCE WITH 10 CFR 54.21(c)(1)(iii) X-1
X.M1 CYCLIC LOAD MONITORING X.M1-1
X.M2 NEUTRON FLUENCE MONITORING X.M2-1
X.S1 CONCRETE CONTAINMENT UNBONDED TENDON PRESTRESS X.S1-1
X.E1 ENVIRONMENTAL QUALIFICATION OF ELECTRIC COMPONENTS X.E1-1

XI AGING MANAGEMENT PROGRAMS XI-1
GUIDANCE ON USE OF LATER EDITIONS/REVISIONS OF VARIOUS INDUSTRY DOCUMENTS XI-5
XI.M1 ASME SECTION XI INSERVICE INSPECTION, SUBSECTIONS IWB, IWC, AND IWD XI.M1-1
XI.M2 WATER CHEMISTRY XI.M2-1
XI.M3 REACTOR HEAD CLOSURE STUD BOLTING XI.M3-1
XI.M4 BOILING WATER REACTOR VESSEL ID ATTACHMENT WELDS XI.M4-1
XI.M5 BOILING WATER REACTOR FEEDWATER NOZZLE XI.M5-1
XI.M6 DELETED XI.M6-1
XI.M7 BOILING WATER REACTOR STRESS CORROSION CRACKING XI.M7-1
XI.M8 BOILING WATER REACTOR PENETRATIONS XI.M8-1
XI.M9 BOILING WATER REACTOR VESSEL INTERNALS XI.M9-1
XI.M10 BORIC ACID CORROSION XI.M10-1
XI.M11B CRACKING OF NICKEL-ALLOY COMPONENTS AND LOSS OF MATERIAL DUE TO BORIC ACID-INDUCED CORROSION IN REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS (PRESSURIZED WATER REACTORS ONLY) XI.M11B-1
XI.M12 THERMAL AGING EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL XI.M12-1
XI.M16A DELETED XI.M16A-1
XI.M17 FLOW-ACCELERATED CORROSION XI.M17-1
XI.M18 BOLTING INTEGRITY XI.M18-1

XI.M19 STEAM GENERATORS XI.M19-1
XI.M20 OPEN-CYCLE COOLING WATER SYSTEM XI.M20-1
XI.M21A CLOSED TREATED WATER SYSTEMS XI.M21A-1
XI.M22 BORAFLEX MONITORING XI.M22-1
XI.M23 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS XI.M23-1
XI.M24 COMPRESSED AIR MONITORING XI.M24-1
XI.M25 BOILNG WATER REACTOR WATER (BWR) REACTOR WATER CLEANUP SYSTEM XI.M25-1
XI.M26 FIRE PROTECTION XI.M26-1
XI.M27 FIRE WATER SYSTEM XI.M27-1
XI.M29 ABOVEGROUND METALLIC TANKS XI.M29-1
XI.M30 FUEL OIL CHEMISTRY XI.M30-1
XI.M31 REACTOR VESSEL MATERIAL SURVEILLANCE XI.M31-1
XI.M32 ONE-TIME INSPECTION XI.M32-1
XI.M33 SELECTIVE LEACHING XI.M33-1
XI.M35 ASME CODE CLASS 1 SMALL-BORE PIPING XI.M35-1
XI.M36 EXTERNAL SURFACES MONITORING OF MECHANICAL COMPONENTS XI.M36-1
XI.M37 FLUX THIMBLE TUBE INSPECTION XI.M37-1
XI.M38 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS XI.M38-1
XI.M39 LUBRICATING OIL ANALYSIS XI.M39-1
XI.M40 MONITORING OF NEUTRON-ABSORBING MATERIALS OTHER THAN BORAFLEX XI.M40-1
XI.M41 BURIED AND UNDERGROUND PIPING AND TANKS XI.M41-1
XI.M42 INTERNAL COATINGS/LININGS FOR IN SCOPE PIPING, PIPING COMPONENTS, HEAT EXCHANGERS, AND TANKS XI.M42-1
XI.S1 ASME SECTION XI, SUBSECTION IWE XI.S1-1
XI.S2 ASME SECTION XI, SUBSECTION IWL XI.S2-1
XI.S3 ASME SECTION XI, SUBSECTION IWF XI.S3-1
XI.S4 10 CFR Part 50, APPENDIX J XI.S4-1
XI.S5 MASONRY WALLS XI.S5-1
XI.S6 STRUCTURES MONITORING XI.S6-1
XI.S7 INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS XI.S7-1
XI.S8 PROTECTIVE COATING MONITORING AND MAINTENANCE XI.S8-1
XI.E1 ELECTRICAL INSULATION FOR ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS XI.E1-1
XI.E2 ELECTRICAL INSULATION FOR ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS XI.E2-1
XI.E3A ELECTRICAL INSULATION FOR INACCESSIBLE MEDIUM VOLTAGE POWER CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS XI.E3A-1
XI.E3B ELECTRICAL INSULATION FOR INACCESSIBLE INSTRUMENT AND CONTROL CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS XI.E3B-1

XI.E3C ELECTRICAL INSULATION FOR INACCESSIBLE LOW VOLTAGE POWER CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS XI.E3C-1
XI.E4 METAL-ENCLOSED BUS XI.E4-1
XI.E5 FUSE HOLDERS XI.E5-1
XI.E6 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS XI.E6-1
XI.E7 HIGH VOLTAGE INSULATORS XI.E7-1

APPENDIX A—QUALITY ASSURANCE FOR AGING MANAGEMENT PROGRAMS A–1

APPENDIX B—OPERATING EXPERIENCE FOR AGING MANAGEMENT PROGRAMS B–1

LIST OF TABLES

Table Page

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

1 Aging Management Review Column Heading Descriptions xxxii
2 Aging Management Programs Element Descriptions xxxiii

APPLICATION OF THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS CODE

I-1 ASME Section XI Editions and Addenda that Are Acceptable for Use in AMPs I-3

CHAPTER II CONTAINMENT STRUCTURES

A1 Concrete Containments (Reinforced and Prestressed) .... II A1-2
A2 Steel Containments .... II A2-2
A3 Common Components .... II A3-2
B1.1 Mark I Steel Containments .... II B1-2
B1.2 Mark I Concrete Containments .... II B1-4
B2.1 Mark II Steel Containments .... II B2-2
B2.2 Mark II Concrete Containments .... II B2-4
B3.1 Mark III Steel Containments .... II B3-2
B3.2 Mark III Concrete Containments .... II B3-6
B4 Common Components .... II B4-2

CHAPTER III STRUCTURES AND COMPONENT SUPPORTS

A1 Group 1 Structures (BWR Reactor Bldg., PWR Shield Bldg., Control Room/Bldg .... III A1-2
A2 Group 2 Structures (BWR Reactor Bldg. With Steel Superstructure).......... III A2-2
A3 Group 3 Structures (Auxiliary Bldg., Diesel Generator Bldg., Radwaste Bldg., Turbine Bldg., Switchgear Rm., Yard Structures Such As AFW Pumphouse Utility/Piping Tunnels, Security/Lighting Poles, Manholes, Duct Banks; SBO Structures Such As Transmission Towers, Startup Tower Circuit Breaker Foundation, Electrical Enclosure)... III A3-2
A4 Group Structures (Containment Internal Structures, Excluding Refueling Canal).. III A4-2
A5 Group 5 Structures, (Fuel Storage Facility, Refueling Canal) .... III A5-2
A6 Group 6 Structures (Water-Control Structures).. III A6-2
A7 Group 7 Structures (Concrete Tanks and Missile Barriers)........................ III A7-2
A8 Group 8 Structures (Steel Tanks and Missile Barriers) .... III A8-2
A9 Group 9 Structures (BWR Unit Vent Stack)... III A9-2
B1.1 Class 1 .... III B1-2
B1.2 Class 2 and 3 .... III B1-6
B1.3 Class MC .... III B1-9
B2 Support for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, NonASME Piping and Components .... III B2-2
B3 Anchorage of Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation... III B3-2
B4 Supports for Emergency Diesel Generator, HVAC System Components, and Other Miscellaneous Mechanical Equipment .... III B4-2

B5 Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Miscellaneous Structures .... III B5-2

CHAPTER IV REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM
A1 Reactor Vessel (BWR) .... IV A1-2
A2 Reactor Vessel (PWR) .... IV A2-2
B1 Reactor Vessel Internals (BWR).................... IV B1-2
B2 Reactor Vessel Internals (PWR)—Westinghouse .... IV B2-2
B3 Reactor Vessel Internals (PWR)—Combustion Engineering.................... IV B3-2
B4 Reactor Vessel Internals (PWR)—Babcock & Wilcox .... IV B4-2
C1 Reactor Coolant, Pressure Boundary (BWR) ....IV C1-2
C2 Reactor Coolant System and Connected Lines (PWR)....................IV C2-2
D1 Steam Generator (Recirculation)....................IV D1-2
D2 Steam Generator (Once-Through) ....IV D2-2
E Common Miscellaneous Material/Environment Combinations .... IV E-2

CHAPTER V ENGINEERED SAFETY FEATURES
A Containment Spray system (PWR).................... V A-2
B Standby Gas Treatment System (BWR).................... V B-2
C Containment Isolation Components ....V C-2
D1 Emergency Core Cooling System (PWR)....................V D1-2
D2 Emergency Core Cooling System (BWR)....................V D2-2
E External Surfaces of Components and Miscellaneous Bolting .... V E-2
F Common Miscellaneous Material/Environment Combinations .... V F-2

CHAPTER VI ELECTRICAL COMPONENTS
A Equipment Not Subject to 10 CFR 50.49 Environmental Qualification Requirements .... VI A-2
B Equipment Subject to 10 CFR 50.49 Environmental Qualification Requirements .... VI B-2

CHAPTER VII AUXILIARY SYSTEMS
A1 New Fuel Storage.................... VII A1-2
A2 Spent Fuel Storage .... VII A2-2
A3 Spent Fuel Pool Cooling and Cleanup (PWR) .... VII A3-2
A4 Spent Fuel Pool Cooling and Cleanup (BWR) .... VII A4-2
B Overhead Heavy Load and Light Load (Related to Refueling Handling Systems) .... VII B-2
C1 Open-Cycle Cooling Water System (Service Water System)....................VII C1-2
C2 Closed-Cycle Cooling Water System ....VII C2-2
C3 Ultimate Heat Sink....................VII C3-2
D Compressed Air System....................VII D-2
E1 Chemical and Volume Control System (PWR).................... VII E1-2
E2 Standby Liquid Control System (BWR) .... VII E2-2
E3 Reactor Water Cleanup System (BWR) .... VII E3-2
E4 Shutdown Cooling System (Older BWR).................... VII E4-2
E5 Waste Water Systems.................... VII E5-2
F1 Control Room Area Ventilation System .... VII F1-2
F2 Auxiliary and Radwaste Area Ventilation System.................... VII F2-2
F3 Primary Containment Heating and Ventilation System.................... VII F3-2
F4 Diesel Generator Building Ventilation System.................... VII F4-2

G Fire Protection ....VII G-3
H1 Diesel Fuel Oil System ....VII H1-2
H2 Emergency Diesel Generator System ....VII H2-2
I External Surfaces of Components and Miscellaneous Bolting .... VII I-2
J Common Miscellaneous Material/Environment Combinations ....VII J-2

CHAPTER VIII STEAM AND POWER CONVERSION SYSTEM
A Steam Turbine System ....VIII A-2
B1 Main Steam System (PWR)....VIII B1-2
B2 Main Steam System (BWR)....VIII B2-2
C Extraction Steam System ....VIII C-2
D1 Feedwater Systems (PWR) ....VIII D1-2
D2 Feedwater Systems (BWR) ....VIII D2-2
E Condensate System ....VIII E-2
F Steam Generator Blowdown System (PWR).... VIII F-2
G Auxiliary Feedwater System (PWR) ....VIII G-2
H External Surfaces of Components and Miscellaneous Bolting ....VIII H-2
I Common Miscellaneous Material/Environment Combinations .... VIII I-2

CHAPTER IX USE OF TERMS FOR STRUCTURES, COMPONENTS, MATERIALS, ENVIRONMENTS, AGING EFFECTS, AND AGING MECHANISMS
IX.B Use of Terms for Structures and Components .... IX B-2
IX.C Use of Terms for Materials ....IX C-2
IX.D Use of Terms for Environments....IX D-2
IX.E Use of Terms for Aging Effects.... IX E-2
IX.F Use of Terms for Aging Mechanisms .... IX F-2

CHAPTER X AGING MANAGEMENT PROGRAMS THAT MAY BE USED TO DEMONSTRATE ACCEPTABILITY OF TIME-LIMITED AGING ANALYSES IN ACCORDANCE WITH 10 CFR 54.21(c)(1)(III)
X-01 FSAR Supplement Summaries for GALL-SLR Report Chapter X Aging Management Programs That May Be Used to Demonstrate Acceptability of Time-Limited Aging Analyses in Accordance with 10 CFR 54.21(c)(1)(iii).... X 01-1
X-02 FSAR Supplement Summaries for GALL-SLR Report Aging Management Programs Discussed in SRP-SLR Chapter 4 .... X 02-1

CHAPTER XI AGING MANAGEMENT PROGRAMS
XI.M12-1 Thermal Embrittlement Susceptibility XI.M12-2
XI.M27-1 Fire Water System Inspection and Testing Recommendations.... XI.M27-4
XI.M29-1 Tank Inspection Recommendations XI.M29-3
XI.M32-1 Examples of Parameters Monitored or Inspected and Aging Effect for Specific Structure or Component.... XI.M32-4
XI.M35-1 Examinations.... XI.M35-5
XI.M41-1 Preventive Actions for Buried and Underground Piping and Tanks XI.M41-2
XI.M41-2 Inspection of Buried and Underground Piping and Tanks.... XI.M41-4
XI.M41-3 Cathodic Protection Acceptance Criteria.... XI.M41-10
XI.M42-1 Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers XI.M42-4
XI-01 FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR .... XI 01-1

LIST OF CONTRIBUTORS1

Division of License Renewal, Office of Nuclear Reactor Regulation

B. Holian	Division Director
C. Miller	Division Director
J. Lubinski	Division Director
R. Caldwell	Deputy Division Director
M. Delligatti	Deputy Division Director
M. Galloway	Deputy Division Director
J. Marshall	Deputy Division Director
S. Weerakkody	Deputy Division Director
S. Bloom	Branch Chief
Y. Diaz	Branch Chief
M. Marshall	Branch Chief
D. Morey	Branch Chief
B. Pham	Branch Chief
B. Wittick	Branch Chief
A. Hiser	Senior Technical Advisor
B. Brady	Technical Project Manager Lead
W. Burton	Regulatory Project Manager Lead
A. Billoch	Lead Project Manager
H. Jones	Lead Project Manager
J. Mitchell	Lead Project Manager
R. Plasse	Lead Project Manager
B. Rogers	Lead Project Manager
E. Sayoc	Lead Project Manager
E. Gettys	Public Coordination
A. Kazi	Public Coordination
A. Bufford	Structural Engineering
D. Brittner	Project Manager
C. Doutt	Electrical Engineering
B. Fu	Mechanical Engineering
W. Gardner	Mechanical Engineering
J. Gavula	Mechanical Engineering
B. Grange	Project Manager
K. Green	Mechanical Engineering
W. Holston	Mechanical Engineering

[1]The titles in this List of Contributions refer to the NRC staff's role in the development of this document, not their current position.

C. Hovanec	Mechanical Engineering
R. Kalikian	Mechanical Engineering
B. Litkett	Project Manager

Division of License Renewal, Office of Nuclear Reactor Regulation

J. Medoff	Mechanical Engineering
S. Min	Mechanical Engineering
A. Prinaris	Structural Engineering
M. Sadollah	Structural Engineering
G. Thomas	Structural Engineering
M. Yoo	Mechanical Engineering

Office of Nuclear Reactor Regulation

D. Alley	Branch Chief
S. Bailey	Branch Chief
R. Dennig	Branch Chief
C. Jackson	Branch Chief
A. Klein	Branch Chief
G. Kulesa	Branch Chief
T. Lupold	Branch Chief
S. Rosenberg	Branch Chief
J. Zimmerman	Branch Chief
R. Hardies	Senior Level Advisor
K. Karwoski	Senior Level Advisor
L. Banic	Project Manager
G. Cheruvenki	Materials Engineering
J. Collins	Materials Engineering
S. Cumblidge	Materials Engineering
A. Erickson	Structural Engineering
C. Fairbanks	Materials Engineering
M. Hardgrove	Mechanical Engineering
K. Hoffman	Materials Engineering
A. Johnson	Reactor Operations Engineering
S. Jones	Reactor Systems Engineering
B. Lee	Reactor Systems Engineering
B. Lehman	Structural Engineering
R. Mathew	Electrical Engineering
I. Naeem	Fire Protection Engineering
C. Ng	Mechanical Engineering
D. Nguyen	Electrical Engineering
A. Obodoako	Materials Engineering
B. Parks	Reactor Engineering
J. Poehler	Materials Engineering

Office of Nuclear Reactor Regulation

P. Purtscher	Materials Engineering
S. Ray	Electrical Engineering
S. Sheng	Materials Engineering
A. Tsirigotis	Mechanical Engineer
O. Yee	Reactor Systems Engineering
M. Yoder	Chemical Engineering
P. Verdi	Foreign Assignee

Region II

P. Cooper	Sr. Reactor Inspector
J. Rivera-Ortiz	Reactor Inspector

Region III

N. Feliz-Adorno	Sr. Reactor Inspector
M. Holmberg	Sr. Reactor Inspector
C. Tilton	Sr. Reactor Inspector

Region IV

S. Graves	Sr. Reactor Inspector
G. Pick	Sr. Reactor Inspector
M. Williams	Reactor Inspector

Office of New Reactors

J. Xu	Branch Chief
A. Istar	Structural Engineering

Office of Nuclear Materials and Safeguards

A. Csontos	Branch Chief
J. Wise	Materials Engineering

Office of Nuclear Regulatory Research

J. Burke	Branch Chief
S. Frankl	Branch Chief
M. Gavrilas	Branch Chief
J. Nakoski	Branch Chief
W. Ott	Branch Chief
D. Rudland	Branch Chief
M. Salley	Branch Chief
R. Sydnor	Branch Chief
J. Ake	Senior Technical Advisor—Geophysical Engineering
T. Nicholson	Senior Technical Advisor—Radionuclide Transport
R. Tregoning	Senior Technical Advisor—Materials Engineering
A. Hull	Team Leader

Office of Nuclear Regulatory Research

K. Arai	Materials Engineering
M. Benson	Materials Engineering
E. Focht	Materials Engineering
M. Fuhrman	Geochemistry
C. Harris	Materials Engineering
M. Hiser	Materials Engineering
M. Homiack	Mechanical Engineering
M. Kirk	Materials Engineering
B. Lin	Mechanical Engineering
S. Malik	Materials Engineering
K. Miller	Electrical Engineering
W. Norris	Materials Engineering
G. Oberson	Materials Engineering
R. Perkins	Reliability & Risk Engineering
I. Prokofiev	Materials Engineering
J. Philip	Geotechnical Engineering
A. Pulvirenti	Materials Engineering
S. Rao	Materials Engineering
M. Rossi	Materials Engineering
M. Sircar	Structural Engineering
M. Srinivasan	Materials Engineering
G. Stevens	Materials Engineering
D. Stroup	Fire Protection Engineering
G. Wang	Mechanical Engineering

Center for Nuclear Waste Regulatory Analyses, Southwest Research Institute®

G. Adams	Computer/Industrial Engineering
L. Howard	Project Manager/Nuclear Engineering
L. Naukam	Program Support/Technical Editing
Y. Pan	Materials Engineering
A. Ramos	Program Support/Technical Editing

ABBREVIATIONS

ACAR	aluminum conductor aluminum alloy reinforced
ACSR	aluminum conductor steel reinforced
ACI	American Concrete Institute
ADAMS	Agencywide Documents Access and Management System
ADS	automatic depressurization system
AEA	Atomic Energy Act
AEC	Atomic Energy Commission
AFW	auxiliary feedwater
AERM	aging effect requiring management
AISC	American Institute of Steel Construction
Al	Aluminum
ALARA	as low as reasonably achievable
AMPs	aging management programs
AMR	aging management review
ANSI	American National Standards Institute
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASTM	ASTM International
B&PV	boiler and pressure vessel
B&W	Babcock & Wilcox
BWR	boiling water reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CASS	cast austenitic stainless steel
CB	core barrel
CCCW	closed-cycle cooling water
CE	Combustion Engineering
CEA	control element assembly
CFR	*Code of Federal Regulations*
CFS	core flood system
CLB	current licensing basis
CRD	control rod drive
CRDM	control rod drive mechanism
CRDRL	control rod drive return line
CRGT	control rod guide tube
CVCS	chemical and volume control system
DC	direct current
DHR	decay heat removal
DLR	Division of License Renewal

DOE	U.S. Department of Energy
DSCSS	drywell and suppression chamber spray system
EDG	emergency diesel generator
EMDA	Expanded Materials Degradation Assessment
EPDM	ethylene propylene diene monosomer
EPR	ethylene-propylene rubber
EPRI	Electric Power Research Institute
EQ	environmental qualification
FAC	flow-accelerated corrosion
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
GE	General Electric
GL	generic letter
HDPE	high density polyethylene
HELB	high-energy line break
HP	high pressure
HPCI	high-pressure coolant injection
HPCS	high-pressure core spray
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
IAEA	International Atomic Energy Agency
I&C	instrumentation and control
IASCC	irradiation assisted stress corrosion cracking
IC	isolation condenser
ID	inside diameter
IEB	inspection and enforcement bulletin
IEEE	Institute of Electrical and Electronics Engineers
IGA	intergranular attack
IGSCC	intergranular stress corrosion cracking
IMI	incore monitoring instrumentation
IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment

IR	insulation resistance
IRM	intermediate range monitor
IRS	Incident Reporting System
ISG	interim staff guidance
ISI	inservice inspection
LERs	licensee event reports
LG	lower grid
LOCA	loss of coolant accident
LP	low pressure
LPCI	low-pressure coolant injection
LPCS	low-pressure core spray
LPM	loose part monitoring
LPRM	low-power range monitor
LPSI	low-pressure safety injection
LRA	license renewal application
LR-ISG	License Renewal Interim Staff Guidance
LRT	leak rate test
LWR	light water reactor
MEAP	material/environment/aging effect/program
MIC	microbiologically influenced corrosion
MRP	Materials Reliability Program
MS	main steam
MSR	moisture separator/reheater
MT	magnetic particle testing
NDE	nondestructive examination
NEA	Nuclear Energy Agency
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NPAR	nuclear plant aging research
NPP	nuclear power plant
NPS	nominal pipe size
NRC	Nuclear Regulatory Commission
NRMS	normalized root mean square
NRR	Office of Nuclear Reactor Regulation
NSAC	Nuclear Safety Analysis Center
NSSS	nuclear steam supply system
NUMARC	Nuclear Management and Resources Council

OCCW	open-cycle cooling water
OD	outside diameter
ODSCC	outside diameter stress corrosion cracking
OECD	Organization for Economic Co-operation and Development
OE	operating experience
OM	operation and maintenance
PT	penetrant testing
PVC	polyvinyl chloride
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
QA	quality assurance
RCCA	rod control cluster assemblies
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RES	Office of Nuclear Regulatory Research
RG	Regulatory Guide
RHR	residual heat removal
RMS	root mean square
RWCU	reactor water cleanup
RWST	refueling water storage tank
RWT	refueling water tank
SAW	submerged arc weld
SBO	station blackout
SCs	structures and components
SCC	stress corrosion cracking
SDC	shutdown cooling
SFP	spent fuel pool
SG	steam generator
S/G	standards and guides
SIL	services information letter
SIT	safety injection tank
SLC	standby liquid control
SLR	subsequent license renewal
SLRAs	subsequent license renewal applications
SLRAAI	subsequent license renewal applicant action items
SOCs	Statement of Considerations

SOER	significant operating experience report
SRM	source range monitor
SRM	staff requirements memorandum
SRP-LR	Standard Review Plan for License Renewal
SS	stainless steel
SSCs	systems, structures, and components
TGSCC	transgranular stress corrosion cracking
TLAA	time-limited aging analysis
UCS	Union of Concerned Scientists
UHS	ultimate heat sink
USI	unresolved safety issue
UT	ultrasonic testing
UV	ultraviolet
XPLE	cross-linked polyethylene

INTRODUCTION

NUREG–2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," is referenced as a technical basis document in NUREG–2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR)." The Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report lists generic aging management reviews (AMRs) of systems, structures, and components (SSCs) that may be in the scope of subsequent license renewal applications (SLRAs) and identifies aging management programs (AMPs) that are determined to be acceptable to manage aging effects of SSCs in the scope of license renewal, as required by 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." If an applicant credits an AMP described in the GALL-SLR Report in the SLRA, the applicant should ensure that the conditions and operating experience (OE) at the plant are bounded by the conditions and OE for which the GALL-SLR Report program was evaluated. If these bounding conditions are not met, the applicant should address any additional aging effects and augment the AMPs for subsequent license renewal (SLR). If an SLRA references the GALL-SLR Report as the approach used to manage aging effect(s), the U.S. Nuclear Regulatory Commission (NRC) 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 (AEA) 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 outcome of an assessment to determine if the nuclear facility can continue to operate safely during the proposed period of extended operation. There are no limitations in the AEA 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 (SSCs) 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 to 80 years), the Office of Nuclear Reactor Regulation (NRR) requested support from the Office of Nuclear Regulatory Research (RES) to develop technical information to evaluate the feasibility of SLR. RES has memoranda of understanding with both the U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI) to cooperate in 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, the Nuclear Energy Institute (NEI) 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 for 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 (SCC) of reactor internals; concrete structures and containment degradation; and electrical cable environmental qualification (EQ), 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 operation beyond 60 years.

The NRC, in cooperation with the DOE, completed the Expanded Materials Degradation Assessment (EMDA) in 2014 (ADAMS Accession Nos. ML14279A321, ML14279A331, ML14279A349, ML14279A430, and ML14279A461). The EMDA uses an expert elicitation process to identify materials and components which 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 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. In addition to working with external stakeholders, the NRC staff conducted aging management program (AMP) effectiveness audits at three units that were at least 2 years into the period of extended operation. The purpose of these 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 ensure that SLR guidance is fully informed by the licensee's 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 NPP 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).

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: (i) International Reporting System, jointly operated by the IAEA; (ii) IAEA's International Generic Ageing Lessons Learned Programme; (iii) Organization for Economic Co-operation and Development (OECD)/Nuclear Energy Agency (NEA) Component Operational Experience and Degradation and Ageing Programme database; and (iv) OECD/NEA 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 for assuring the safe operation of NRC-licensed nuclear power plant (NPPs). By letter dated August 6, 2014 (ADAMS Accession No. ML14253A104), NEI documented the industry's views and recommendations for updating NUREG–1801 Revision 2, "Generic Aging Lessons Learned (GALL) Report," and NUREG–1800 Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," to support SLR. Between fiscal years 2014 and 2015, the NRC staff reviewed the comments and recommendations and drafted the GALL-SLR Report to ensure that sufficient guidance was in place to support review of an SLR application in 2018 or 2019.

The staff requirements memorandum (SRM) 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 on the implementation of the license renewal regulatory framework. The SRM also directed the staff to keep the Commission informed on the progress in resolving the following technical issues related to SLR: (i) reactor pressure vessel neutron embrittlement at high fluence, (ii) irradiation assisted SCC of reactor internals and primary system components, (iii) concrete and containment degradation, and (iv) electrical cable qualification and condition assessment. In addition, the SRM directed that the staff should keep the Commission informed regarding the staff's readiness for accepting an application and any further need for regulatory process changes, rulemaking, or research.

The GALL-SLR report also includes the NRC staff's resolutions of License Renewal Interim Staff Guidance's (LR-ISGs) from 2011 through 2015. Under the LR-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 LR-ISG, issues it for public comment, evaluates any comments received, and, if necessary, issues the final LR-ISG.

The LR-ISG is then used until the NRC staff incorporates the revised guidance into a formal license renewal guidance document revision. The LR-ISGs addressed in the GALL-SLR report are:

- LR-ISG-2011-01: Aging Management of Stainless Steel Structures and Components in Treated Borated Water, Revision 1
- LR-ISG-2011-02: Aging Management Program for Steam Generators
- LR-ISG-2011-03: Generic Aging Lessons Learned (GALL) Report Revision 2 AMP XI.M41, “Buried and Underground Piping and Tanks”
- LR-ISG-2011-04: Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors
- LR-ISG-2011-05: Ongoing Review of Operating Experience
- LR-ISG-2012-01: Wall Thinning Due to Erosion Mechanisms
- LR-ISG-2012-02: Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation
- 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
- LR-ISG-2015-01: Changes to Buried and Underground Piping and Tank Recommendations

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 contains 11 chapters and two appendices. The majority 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 (NPPs). The major plant systems include the containment structures (Chapter II), structures and component 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 (ASME) code for subsequent license renewal (SLR). Chapter IX contains definitions of a selection of standard terms used within the GALL-SLR Report. Chapter X contains examples of AMPs that may be used to demonstrate the acceptance of time-limited aging analysis (TLAAs) in accordance with 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 (OE).

The evaluation process for the AMPs and the application of the GALL-SLR Report is described in this document. The aging management review (AMR) 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 contained in this report.

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 following 10 program elements in each AMP, as defined in Table 2.

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

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

Table 1. Aging Management Review Column Heading Descriptions	
Column Heading	**Description**
New (N), Modified (M), Deleted (D) Item	Identifies the item as new to GALL-SLR Report, modified from GALL Revision 2, deleted from GALL Revision 2, or if blank, is unchanged from GALL Revision 2. The NRC will publish the technical bases for these new, modified, and deleted AMR items in a NUREG containing the disposition of public comments and the technical bases for changes in the guidance documents when the final SLR guidance documents are published.
Item	Identifies a unique number for the item (i.e., VII.G.A-91). The first part of the number indicates the chapter and AMR 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).
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.
Aging Effect/ Mechanism	Identifies the applicable aging effect and mechanism(s). See Chapters IX.E and IX.F of this report for more information on applicable aging effects/mechanisms.
Aging Management Program (AMP)/TLAA	Identifies an AMP/TLAA found acceptable for adequately managing the effects of aging. See Chapters X and XI of this report.
Further Evaluation	Identifies whether a further evaluation is needed.

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 AMR.
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 or parameters that will be monitored and how the monitoring of these parameters will ensure adequate aging management.
4. Detection of Aging Effects	Detection of aging effects should occur before there is a loss of any structure and component intended function. 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 ensure 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 ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
9. Administrative Controls	Administrative controls should provide a formal review and approval process.
10. Operating Experience	Operating experience applicable to the AMP, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure- and component intended function(s) will be maintained during the subsequent period of extended operation. In addition, an ongoing review of both plant-specific and industry OE ensures that the AMP is effective in managing the aging effects for which it is credited. The AMP is either 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.

APPLICATION OF THE GENERIC AGING LESSONS LEARNED FOR SUBSEQUENT LICENSE RENEWAL REPORT

The Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report is a technical basis document to the Standard Review Plan for Subsequent License Renewal (SRP-SLR), which provides the staff with guidance in 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 a 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 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 on-site in an auditable form.

The GALL-SLR Report contains one acceptable way to manage aging effects for 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 (NRC) staff.

The GALL-SLR Report does not address scoping of structures and components (SCs) for license renewal; this is addressed in SRP-SLR 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 this particular structure or component is within the scope of license renewal for all plants. Conversely, the omission of a certain structure or component in the GALL-SLR Report does not imply that this 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 SCs 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 to manage aging effects for particular structures or components for SLR without change. The GALL-SLR Report also contains recommendations on 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 (SSCs) 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. Those aspects of the aging management review (AMR) process that affect the quality of safety-related SSCs are subject to the QA requirements of Appendix B to 10 CFR Part 50. For nonsafety-related-SCs subject to an AMR, 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 subsequent license renewal (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 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

A. INTRODUCTION

B. STRUCTURES AND COMPONENTS

C. MATERIALS

D. ENVIRONMENTS

E. AGING EFFECTS

F. SIGNIFICANT AGING MECHANISMS

G. REFERENCES

A. INTRODUCTION

This chapter is designed to clarify the usage 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 revised from the Generic Aging Lessons Learned (GALL) Report, Revision 2, to enhance the report's applicability to future subsequent license renewal applications (SLRA). The U.S. Nuclear Regulatory Commission (NRC) has also added several new terms, and removed, and clarified some of those that were in the GALL Report, Revision 2.

B. STRUCTURES AND COMPONENTS

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

IX.B Use of Terms for Structures and Components

Term	Usage 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 nonClass 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 that 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 components	Ducting and components include 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 bolts or HVAC piping.
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, and containment isolation system, and refueling water storage tank, etc.) can include encapsulation vessels, piping, and valves.
External surfaces	In the context of SCs, the term “external surfaces” is used to represent the external surfaces of SCs, such as tanks, that are not specifically listed elsewhere.
Heat exchanger components	A heat exchanger is a device that transfers heat from one fluid to another without the fluids coming in contact with each other. This includes air handling units and other devices that cool or heat fluids. Heat exchanger components may include, but are not limited to, air handling unit cooling and heating coils, piping/tubing, shell, plates/frames, tubesheets, tubes, valves, and bolting. Although tubes are the primary heat transfer components, heat exchanger internals, including tubesheets and fins, contribute to heat transfer and may be affected by reduction of heat transfer due to fouling [Ref. 1]. The inclusion of components such as tubesheets is dependent on manufacturer specifications.
High voltage insulators	An insulator is an insulating material in a configuration designed to physically support a conductor and separate the conductor electrically from other conductors or objects. The high voltage insulators that are evaluated for license renewal are those used to support and insulate high voltage electrical components in switchyards, switching stations and transmission lines.
Inaccessible Areas of Structural Components for non- ASME 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 as defined below: • below-grade surfaces exposed to foundation soil/material, backfill, or ground water • portions of concrete surfaces that are covered by metallic liners

IX.B Use of Terms for Structures and Components

Term	Usage in this document
	• 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	"Metal enclosed bus" (MEB) is the term used in electrical and industry standards (IEEE and ANSI) for electrical buses installed on electrically-insulated supports constructed with all phase conductors enclosed in a metal enclosure.
Piping, piping components, piping elements, 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, 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.). As used in GALL-SLR Report AMP XI.M41, buried piping and tanks are in direct contact with soil or concrete (e.g., a wall penetration). 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 restricted.
Piping elements	The category of "piping elements" is a subcategory of piping, piping components, and piping elements that in the GALL-SLR Report, applies only to components made of glass (e.g., sight glasses and level indicators, etc.) 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 CRD head penetration (it is only of concern in Section A2 for PWR reactor vessels).
Reactor coolant pressure boundary components	Reactor coolant pressure boundary components include, but are not limited to, piping, piping components, piping elements, 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 components used as sealants or gaskets.
Steel elements: liner; liner anchors;	This category includes steel liners used in suppression pools or spent fuel pools.

IX.B Use of Terms for Structures and Components

Term	Usage in this document
integral attachments	
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, “Aboveground Metallic 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.
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 bus.
Vibration isolation elements	This category includes nonsteel supports used for supporting components prone to vibration.

C. MATERIALS

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

IX.C Use of Terms for Materials

Term	Usage in this document
Aluminum	Aluminum (Al) alloy and heat treatment temper designations are used in accordance with ANSI document: ANSI H35.1/H35.1(M).
Boraflex	Boraflex is a material that is composed of 46 percent silica, 4 percent polydimethylsiloxane polymer, and 50 percent 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 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; these alloys can contain up to 10 percent boron as AlB_{12} intermetallics.
Cast austenitic stainless steel	Cast austenitic stainless steel (CASS) alloys, such as CF-3, CF-8, CF-3M, and CF-8M, have been widely used in LWRs. These CASS alloys are similar to wrought grades Type 304L, Type 304, Type 316L, and Type 316, except CASS typically contains 5 to 25 percent 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 have cementitious properties: (i) Portland cement, (ii) blended hydraulic cement, (iii) fly ash, (iv) ground granulated blast furnace slag, (v) silica fume, (vi) calcined clay, (vii) metakaolin, (viii) calcined shale, and (ix) rice husk ash. This category may include asbestos cement.
Copper alloy (≤15% Zn and ≤8% Al)	This category applies to those copper alloys whose critical alloying elements are below than the thresholds that make them susceptible to stress corrosion cracking, selective leaching, and boric acid corrosion. For example, copper, copper nickel, brass, bronze ≤15% Zn, and aluminum bronze ≤8% Al are resistant to SCC, selective leaching, and boric acid corrosion [Ref. 2]
Copper alloy (>15% Zn or >8% Al)	This category applies to those copper alloys whose critical alloying elements are above the thresholds that make them susceptible to stress corrosion cracking (SCC), selective leaching and boric acid corrosion. Copper-zinc alloys >15% Zn are susceptible to SCC, selective leaching and boric corrosion. Additional copper alloys, such as aluminum bronze > 8% Al, also may be susceptible to SCC or leaching. The elements that are most commonly alloyed with copper are Zn (forming brass), tin (forming bronze), nickel, silicon, Al (forming aluminum-bronze), cadmium, and beryllium. Additional copper alloys may be susceptible to these aging effects if they fall above the threshold for the critical

IX.C Use of Terms for Materials

Term	Usage in this document
	alloying element. [Ref. 2]
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, EPT, EPDM, PTFE, ETFE, viton, vitril, neoprene, and silicone elastomer.
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., EPR (ethylene-propylene rubber), SR (silicone rubber), EPDM (ethylene propylene diene monomer), and XLPE (crosslinked polyethylene) and or ceramics.
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., Na, Mg, Ca, K), and cooling the product rapidly to prevent crystallization or devitrification.
Graphitic tool steel	Graphitic tool steels (such as 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 percent by weight carbon, while cast irons typically have between 2.5 to 4 percent. Gray cast iron contains flat graphite flakes that reduce its strength and form cracks, inducing mechanical failures. They also cause the metal to behave in a nearly brittle fashion, rather than experiencing the elastic, ductile behavior of steel. Fractures in this type of metal tend to take place along the flakes, which give the fracture surface a gray color, hence the name of the metal. Gray cast iron is susceptible to selective leaching, resulting in a significant reduction of the material's strength due to the loss of iron from the microstructure, leaving a porous matrix of graphite. In some environments, gray cast iron is categorized with the group "Steel."
Low-alloy steel, yield strength >150 ksi	Low-alloy steel includes AISI steels 4140, 4142, 4145, 4140H, 4142H, and 4145H (UNS#: G41400, G41420, G41450, H41400, H41420, H41450). Low-alloy steel bolting material, SA 193 Gr. B7, is a ferritic, low-alloy steel for high-temperature service. High-strength low-alloy (Fe-Cr-Ni-Mo) steel bolting materials have a maximum tensile strength of <1172 megapascal (MPa) [<170 kips/square inch (ksi)]. They may be subject to SCC if the actual measured yield strength, S_y, ≥ 150 ksi (1,034 MPa). Bolting fabricated from high-strength (actual measured yield strength, S_y, ≥ 150 ksi or 1,034 MPa) low-alloy steel, SA 193 Gr. B7, is susceptible to stress corrosion cracking. Examples of high-strength alloy steels that comprise this category include SA540-Gr. B23/24, SA193-

IX.C Use of Terms for Materials

Term	Usage in this document
	Gr. B8, and Grade L43 (AISI4340).
Lubrite®	Lubrite® refers to a patented technology in which the bearing substrate (bronze is commonly used, but in unusual environments can range from 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 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 DBA or SSE). 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 ASME Section XI, Subsection IWF (GALL-SLR Report AMP XI.S3) or in Structures Monitoring (GALL-SLR Report AMP XI.S6).
Malleable iron	The term "Malleable iron" usually means malleable cast iron, characterized by exhibiting some elongation and reduction in area in a tensile test. Malleable iron is one of the materials in the category of "Porcelain, Malleable iron, Al, galvanized steel, cement."
Nickel alloys	Nickel alloys are nickel-chromium-iron (molybdenum) alloys and include the Alloys 600 and 690. Examples of nickel alloys include Alloy 182, 600, and 690, Gr. 688 (X-750), Inconel 182, Inconel 82, NiCrFe, SB-166, -167, and -168, and X-750. [Ref. 3]
Porcelain	Hard-quality porcelain is used as an insulator for supporting high-voltage electrical insulators. Porcelain is a hard, fine-grained ceramic that consists of kaolin, quartz, and feldspar fired at high temperatures.
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 AMR line-item R-85, growth of intergranular separations (underclad cracks) in low-alloy steel forging heat affected zone under austenitic SS cladding is a TLAA to be evaluated for the 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 Section XI Code.
Stainless Steel	Products grouped under the term stainless steel (SS) include austenitic, ferritic, martensitic, 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

Term	Usage in this document
	applicable to all of the various SS categories, it can be assumed that the term "SS" in the "Material" column of an AMR line-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-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 line-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 comprise 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 comprise this category include Type 304, 304NG, 304L, 308, 308L, 309, 309L, 316 and 347. Examples of CASS that comprise this category include CF3, CF3M, CF8 and CF8M. [Ref. 4, 5, 6].
Steel	In some environments, carbon steel, alloy steel, cast iron, gray cast iron, malleable iron, and high-strength low-alloy steel are vulnerable to general, pitting, and crevice corrosion, even though the rates of aging may vary. 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 also is 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 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. [Ref. 4, 5]
Superaustenitic stainless steel	Superaustenitic stainless steels (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

IX.C Use of Terms for Materials

Term	Usage in this document
	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.
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.
Titanium	The category titanium includes unalloyed titanium (ASTM grades 1-4) and various related alloys (ASTM grades 5, 7, 9, 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. 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 percent oxygen or any amount of tin [Ref. 7]. ASTM Grades 1, 2, 7, 11, or 12 are not susceptible to SCC in seawater or brackish raw water [Ref. 8].
Various Organic Polymers Various polymeric materials	Polymers used in electrical applications include 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. Polymers used in mechanical applications are addressed as specific to their material types [e.g., PVC, HDPE, fiberglass) or generically as elastomers used in different components types (e.g., piping, seals, linings, fire barriers)].
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.
Zircaloy-4	Zircaloy-4, (Zry-4), is a member in the group of high- Zr alloys. Such zircaloys are used in nuclear technology, as 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 % zirconium with 1.45% tin, 0.21% iron, 0.1% chromium, and 0.01% hafnium.

D. ENVIRONMENTS

The following table defines many of the standardized environments used in the preceding Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Aging Management Review (AMR) tables in Chapters II through VIII of the GALL-SLR Report. The usage of temperature thresholds for describing aging effects are continued as in the Generic Aging Lessons Learned (GALL) Report, Revision 2.

Temperature Threshold of 35 °C [95 °F] for Thermal Stresses in Elastomers: In general, if the ambient temperature is less than about 35°C [95°F], then thermal aging may be considered not significant for rubber, butyl rubber, neoprene, nitrile rubber, silicone elastomer, fluoroelastomer, ethylene-propylene rubber (EPR), and ethylene propylene diene monosomer (EPDM) [Ref. 9]. Hardening and loss of strength of elastomers 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, it should be noted 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 these instances have identified a significant presence of contaminants (halogens, specifically chlorides) in the failed components. With a harsh enough environment (e.g., significant contamination), SCC can occur in austenitic SS at ambient temperature. In a water environment where the concentration of contaminants (e.g., sulfates, chlorides, fluorides) is maintained consistent with a water chemistry program, these conditions are considered event-driven, resulting from a breakdown of chemistry controls. However in environments where the chemistry is not controlled (e.g., air-outdoor, soil) SCC can occur at ambient temperature. In air-outdoor environments, surface temperatures exposed directly to sunlight will be higher than ambient air conditions [Ref. 8, 10, 11].

Temperature threshold of 250 °C [482 °F] for thermal embrittlement in cast austenitic stainless steel (CASS): CASS subjected to sustained temperatures below 250 °C [482 °F] will not result in a reduction of room temperature Charpy impact energy below 50 foot-pound (ft-lb) for exposure times of approximately 300,000 hours (for CASS with ferrite content of 40 percent and approximately 2,500,000 hours for CASS with ferrite content of 14 percent) [Fig. 2; Ref. 12]. For a maximum exposure time of approximately 420,000 hours (48 EFPY), a screening temperature of 250 °C [482 °F] is conservatively chosen because (1) the majority of 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., 10 CFR Part 50 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.

IX.D Use of Terms for Environments

Term	Usage 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 are represented by specific GALL-SLR AMR items.
Aggressive environment (steel in concrete)	This environment affects steel embedded in concrete with a pH <5.5 or a chloride concentration >500 ppm or sulfate >1,500 ppm. [Ref. 13]
Air–indoor controlled	This environment is one to which the specified internal or external surface of the component or structure is exposed; a humidity-controlled (i.e., air conditioned) environment. For electrical purposes, control must be sufficient to eliminate the cited aging effects of contamination and oxidation without affecting the resistance.
Air–indoor uncontrolled	Uncontrolled indoor air is associated with systems with temperatures higher than the dew point (i.e., condensation can occur, but only rarely; equipment surfaces are normally dry).
Air–outdoor	The outdoor environment consists of moist, possibly salt-laden atmospheric air, ambient temperatures and humidity, and exposure to weather, including precipitation and wind. The component is exposed to air and local weather conditions, including salt water spray (if present). A component is considered susceptible to a wetted environment when it is submerged, has the potential to collect water, or is subject to external 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 PWRs).
Air with leaking secondary-side water and/or steam	This environment applies to steel components in the pressure boundary and structural parts of the once-through steam generator that may be exposed to air with leaking secondary-side water and/or steam.
Air with metal temperature up to 288 °C [550 °F]	This environment is synonymous with the more commonly-used phrase "system temperature up to 288 °C [550 °F]."
Air with reactor coolant leakage	Air and reactor coolant or steam leakage on high temperature systems (germane to BWRs).
Air with steam or water leakage	Air and untreated steam or water leakage on indoor or outdoor systems with temperatures above or below the dew point.
Air, dry	Air that has been treated to reduce its dew point well below the system operating temperature. Within piping, unless otherwise specified, this encompasses either internal or external.
Air, moist	Air with enough moisture to facilitate the loss of material in steel caused by general, pitting, and crevice corrosion. Moist air in the absence of condensation also is potentially aggressive (e.g., under conditions where hygroscopic surface contaminants are present, etc.).
Any	This could be any indoor or outdoor environment where the aging effects are not dependent on environmental conditions.

IX.D Use of Terms for Environments

Term	Usage in this document
Buried and underground	As referenced in GALL-SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks,” 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). 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).
Closed-cycle cooling water	Treated water subject to the closed-cycle cooling water (CCCW) chemistry program is included in this environment. CCCW >60 °C [>140°F] makes the SCC of SS possible. Examples of descriptors that comprise this category can include: (i) chemically-treated, (ii) borated water, and (iii) treated component cooling water demineralized water on one side and CCCW (treated water) on the other side chemically-treated, borated water on the tube side and CCCW on the shell side.
Concrete	This environment consists of components embedded in concrete.
Condensation (internal/external)	Condensation on the surfaces of systems at temperatures below the dew point is considered “raw water” due to the potential for internal or external surface contamination. Under certain circumstances, the former terms “moist air” or “warm moist air” are subsumed by the usage of “condensation,” which describes an environment where there is enough moisture for corrosion to occur. Condensation can form between thermal insulation and a component when air intrusion occurs through minor gaps in the insulation and 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 percent 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 dry air or inert, 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 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.
Ground water/soil	Ground water 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

IX.D Use of Terms for Environments

Term	Usage in this document
	inorganic materials produced by the weathering of rock and clay minerals or the decomposition of vegetation. Voids containing air and moisture can occupy 30 to 60 percent of the soil volume [Ref.14]. Concrete subjected to a ground water/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 ground water or moist soils are subject to the same aging effects as those systems and components exposed to raw water.
Lubricating oil	Lubricating oils are low-to-medium viscosity hydrocarbons that can contain contaminants and/or moisture. This usage 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, piping components, and piping elements, 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.
Raw water	Raw water consists of untreated surface or ground water, whether fresh, brackish, or saline in nature. This includes water for use in OCCW 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 BWRs.
Reactor coolant >250 °C [>482°F]	Treated water above the thermal embrittlement threshold for 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.
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 to 60 percent of the soil volume [Ref.14]. Properties of soil that can affect degradation kinetics include moisture content, pH, ion exchange capacity, density, and hydraulic conductivity.

IX.D Use of Terms for Environments

Term	Usage in this document
	External environments included in the soil category consist of components at the air/soil interface, buried in the soil, or exposed to ground water in the soil. See also “ground water/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 CVCS 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 which 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. 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.
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, ground water, or water flowing under a foundation.
Water-standing	Water that is stagnant and unrefreshed, thus possibly resulting in increased ionic strength up to saturation.

E. AGING EFFECTS

The following table explains the selected usage 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) aging management review (AMR) tables in Chapters II through VIII of the GALL-SLR Report.

IX.E Use of Terms for Aging Effects

Term	Usage 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 cyclic loading.
Cracking	This term is synonymous with the phrase "crack initiation and growth" in metallic substrates. Cracking in concrete when caused by restraint shrinkage, creep, settlement, and aggressive environment.
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 either an air-indoor uncontrolled or air-outdoor environment.
Cumulative fatigue damage	Cumulative fatigue damage is due to fatigue, as defined by ASME Boiler and Pressure Vessel Code.
Denting	Denting in steam generators can result from corrosion of carbon steel tube support plates.
Expansion and cracking	Within concrete structures, expansion and cracking can result from reaction with aggregates.
Fatigue	Fatigue in metallic fuse holder clamps can result from ohmic heating, thermal cycling, electrical transients, frequent manipulation, and vibration. [Ref. 15]
Flow blockage	Flow blockage is the reduction of flow or pressure, or both, in a component due to fouling, which can occur from an accumulation of debris such as particulate fouling (e.g., eroded coatings, corrosion products), biofouling, or macro fouling. Flow blockage can result in a reduction of heat transfer or the inability of a system to meet its intended safety function, or both. This usage is consistent with the usage of the term "pressure boundary" as found in SRP-SLR Table 2.1-4(b), "Typical 'Passive' Component-Intended Functions."
Hardening and loss of strength	Hardening (loss of flexibility) and loss of strength (loss of ability to withstand tensile or compressive stress) can result from elastomer degradation of seals and other elastomeric components. Degraded elastomers can experience increased hardness, shrinkage, loss of sealing, cracking, and loss of strength. Hardening and loss of strength of elastomers can be induced by elevated temperature {over about [95 °F or 35 °C], and additional aging factors (e.g., exposure to ozone, oxidation, photolysis (due to ultraviolet light), and radiation)}. [Ref. 9]
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.
Reduction in impact strength	Long-term (2 years or longer) exposure of PVC piping, piping components, and piping elements to sunlight can result in a reduction in impact strength. Other polymeric materials are subject to

IX.E Use of Terms for Aging Effects

Term	Usage in this document
	embrittlement due to environmental conditions such as sunlight, ozone, chemical vapors, or loss of plasticizers due to evaporation. [Ref. 16]
Increased resistance of connection	Increased resistance of connection is an aging effect that can be caused by the loosening of bolts resulting from thermal cycling and ohmic heating. [Ref. 17, 18] In Chapter VI AMR line-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, and 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 SG tubes may be indicative of support plate damage or ligament cracking.
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 material of the 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 10 CFR 54.4(a)(1) or (a)(3) (e.g., reduction in flow, drop in pressure, reduction in 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,

IX.E Use of Terms for Aging Effects

Term	Usage in this document
	pitting corrosion, galvanic corrosion, crevice corrosion, erosion, fretting, flow-accelerated corrosion, microbiologically-induced 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. For high-voltage insulators, loss of material can be attributed to mechanical wear or wind-induced abrasion. [Ref. 17]
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 hardening. Clearances being less than the design requirements can also contribute to loss of mechanical function.
Loss of preload	Loss of preload can be due to gasket creep, thermal effects (including differential expansion and creep or stress relaxation), and self-loosening (which includes vibration, joint flexing, cyclic shear loads, thermal cycles). [Ref. 19]
Loss of prestress	Loss of prestress in structural steel anchorage components can result from relaxation, shrinkage, creep, or elevated temperatures.
Loss of sealing; leakage through containment	Loss of sealing and leakage through containment in such materials 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.
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 erosion of porous concrete subfoundation.
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 GALL-SLR Report does not include reduction of heat transfer for any heat exchanger surfaces other than tubes, reduction in heat transfer is of concern for other heat exchanger surfaces.

IX.E Use of Terms for Aging Effects

Term	Usage in this document
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 (UV 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 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 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.

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 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) aging management review (AMR) line item tables in Chapters II through VIII of GALL-SLR Report.

IX.F Use of Terms for Aging Mechanisms

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

IX.F Use of Terms for Aging Mechanisms

Term	Usage in this document
	(recirculating) system of a PWR. The tubes pass through drilled holes in the plate. The secondary coolant flows through the tube supports via flow holes between the tubes. [Ref. 22, 23]
Corrosion of embedded steel	If the pH of concrete in which steel is embedded is reduced below 11.5 by intrusion of aggressive ions (e.g., chlorides > 500 ppm) in the presence of oxygen, embedded steel may corrode. A reduction in pH may be caused by the leaching of alkaline products through cracks, entry of acidic materials, or carbonation. Chlorides may be present in the constituents of the original concrete mix. The severity of the corrosion is affected by the properties and types of cement, aggregates, and moisture content. [Ref. 24]
Creep	Creep, for a metallic material, refers to a time-dependent continuous deformation process under constant stress. It is an elevated temperature process and is not a concern for low-alloy steel below 371 °C [700 °F], for austenitic alloys below 538 °C [1,000 °F], or for Ni-based alloys below 982 °C [1,800 °F]. [Ref. 25, 26] Creep, in concrete, is related to the loss of absorbed water from the hydrated cement paste. It is a function of the modulus of elasticity of the aggregate. It may result in loss of prestress in the tendons used in prestressed concrete containment. [Ref. 22]
Crevice corrosion	Crevice corrosion 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. Carbon steel, cast iron, low alloy steels, SS, copper, and nickel base alloys are all susceptible to crevice corrosion. Steel can be subject to crevice corrosion in some cases after lining/cladding degradation. Localized corrosion of a metal surface at, or immediately adjacent to, an area that is shielded from full exposure to the environment because of the close proximity of the metal to the surface of another dissimilar material.
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.
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 degradation	Elastomer degradation is an encompassing term related to various aging mechanisms that result in hardening and loss of strength of elastomers. Degradation can occur in elastomers due to thermal aging {elevated temperature over about 35 °C [95 °F], exposure to ozone, oxidation, photolysis (due to ultraviolet light), and radiation. [Ref. 9] Degradation may include mechanisms such as cracking, crazing, fatigue breakdown, abrasion, chemical attacks, and change in material properties. [Ref. 27, 28]

IX.F Use of Terms for Aging Mechanisms

Term	Usage in this document
Electrical transients	An electrical transient is a stressor caused by a voltage spike that can contribute to aging degradation. Certain types of high-energy electrical transients can contribute to electromechanical forces, ultimately resulting in fatigue or loosening of bolted connections. Transient voltage surges are a major contributor to the early failure of sensitive electrical components.
Elevated temperature	Elevated temperature is referenced as an aging mechanism only in the context of LWR containments (GALL-SLR Chapter II). In concrete, reduction of strength and modulus can be attributed to elevated temperatures {>66 °C [>150°F] general; >93 °C [>200 °F] local}.
Erosion	Erosion is the progressive loss of material due to the mechanical interaction between a surface and a moving fluid. Different forms of erosion include cavitation, flashing, droplet impingement, and solid particle impingement.
Erosion settlement	Erosion settlement is the subsidence of a containment structure that may occur due to changes in the site conditions, (e.g., erosion or changes in the water table). The amount of settlement depends on the foundation material. [Ref. 24] Another synonymous term is “erosion of the porous concrete subfoundation.”
Erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	In earthen water-control structures, the loss of material and loss of form can result from erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage.
Fatigue	Fatigue is a phenomenon leading to fracture under repeated or fluctuating stresses having 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 is governed by factors including stress range, mean stress, loading frequency, surface condition, and the presence of deleterious chemical species. [Ref. 29]
Flow-accelerated corrosion	Flow-accelerated corrosion (FAC) is a corrosion mechanism, which results in wall thinning of carbon steel components exposed to moving, high temperature, low-oxygen water, such as PWR primary and secondary water, and BWR reactor coolant. FAC is the result of dissolution of the surface film of the steel, which is transported away from the site of dissolution by the movement of water. [Ref. 30]
Fouling	Fouling is an accumulation of deposits on the surface of a component or structure. This term includes accumulation and growth of aquatic organisms on a submerged metal surface or the accumulation of deposits (usually inorganic). Biofouling, a subset of fouling, can be caused by either macroorganisms

IX.F Use of Terms for Aging Mechanisms

Term	Usage in this document
	(e.g., barnacles, Asian clams, zebra mussels, or others found in fresh and salt water) or microorganisms (e.g., algae, microfouling tubercles). Fouling also can be categorized as particulate fouling (e.g., sediment, silt, dust, eroded coatings, and corrosion products), biofouling, or macrofouling (e.g., delaminated coatings, debris). Fouling can occur on the piping, valves, and heat exchangers. Fouling can result in a reduction of heat transfer or flow blockage. For "fouling that leads to corrosion," fouling can be an indirect contributor to corrosion but does not directly cause loss of material.
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 (a) adequate air content (i.e., within ranges specified in ACI 301-84), (b) low permeability, (c) protection until adequate strength has developed, and (d) surface coating applied to frequently wet-dry surfaces. [Ref. 24, 31]
Fretting	Fretting is a wear process that occurs at the interface between contacting surfaces that experience a slight, differential oscillatory movement. Fretting can lead to loss of material.
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 AMR line item tables as a specific aging mechanism. The most effective means of mitigating or preventing galvanic corrosion involve design and maintenance activities. For example: (a) selecting dissimilar metals that are as close to each other in the galvanic series; (b) avoiding localized small anodes and large cathodes; (c) instituting means to insulate the dissimilar metals from each other; (d) coatings and (e) sacrificial anodes. Although galvanic corrosion has been removed from the AMR line item tables as a specific aging mechanism, several AMPs support the mitigation or prevention of galvanic corrosion. For example: GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," manages loss of coating integrity. A licensee experienced accelerated galvanic corrosion when loss of coating integrity occurred in the vicinity of carbon steel components attached to AL6XN components. [Ref. 32] GALL-SLR Report AMP XI.M10, "Boric Acid Corrosion," inspections can detect boric acid residue spanning dissimilar metals, which can result in a galvanic corrosion cell. A licensee experienced galvanic corrosion of a steel nozzle when boric acid residue

IX.F Use of Terms for Aging Mechanisms

Term	Usage in this document
	spanned the steel nozzle and attached SS piping. The galvanic corrosion resulted in corrosion rates 1.5 times higher than expected. [Ref. 33] Cracking or pitting of SS or nickel alloy cladding can lead to localized galvanic attack. AMPs XI.M32, "One-Time Inspection," and XI.M21A, "Closed Treated Water Systems," are used to detect cracking due to SSC and loss of material due to pitting and crevice corrosion for clad steel components. [Ref. 33] 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. Loss of material due to general corrosion is an aging effect requiring management for low-alloy steel, carbon steel, and cast iron in outdoor environments. Some potential for pitting and crevice corrosion may exist even when pitting and crevice corrosion is not explicitly listed in the aging effects/aging mechanism column in GALL-SLR Report-AMR items and when the descriptor may only be loss of material due to general corrosion. For example, the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," calls for the inspection of general corrosion of steel through visual inspection of external surfaces for evidence of material loss and leakage. It acts as a de facto screening for pitting and crevice corrosion, since the symptoms of general corrosion will be noticed first. Wastage is thinning of component walls due to general corrosion.
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 Cr and, therefore, susceptible to preferential attack [intergranular attack (IGA)] by a corroding (oxidizing) medium.
Intergranular stress corrosion cracking	Intergranular stress corrosion cracking (IGSCC) is SCC in which the cracking occurs along grain boundaries.
Irradiation assisted stress corrosion cracking	Failure by intergranular cracking in aqueous environments of stressed materials exposed to ionizing radiation has been termed irradiation assisted stress corrosion cracking (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

IX.F Use of Terms for Aging Mechanisms

Term	Usage in this document
	temperature. This leaching action is effective only if the water passes through the concrete. [Ref. 24]
Low-temperature crack propagation	LTCP is IGSCC at low temperatures ~54–77 °C [~130–170 °F].
Long-term loss of material	Long term loss of material is associated with general corrosion of steel components exposed to a water environment that has not included corrosion inhibitors as a preventive action [i.e., treated water, reactor coolant, raw water, or waste water]. Loss of material is managed by conducting volumetric examinations in order to determine whether general corrosion could challenge the component's structural integrity such that a loss of intended function might occur during periods of extended operation [e.g., pressure boundary, leakage boundary (spatial), structural integrity (attached), as defined in SRP-SLR Table 2.1-4(b)].
Mechanical loading	Applied loads of mechanical origins rather than from other sources, such as thermal.
Mechanical wear	See "Wear."
Microbiologically-induced corrosion	Any of the various forms of corrosion induced by the presence and activities of such microorganisms as bacteria, fungi, and algae, and/or the products produced in their metabolism. Degradation of material that is accelerated due to conditions under a biofilm or microfouling tubercle, for example, anaerobic bacteria that can set up an electrochemical galvanic reaction or inactivate a passive protective film, or acid-producing bacterial that might produce corrosive metabolites.
Moisture intrusion	Influx of moisture through any viable process.
Neutron irradiation embrittlement	Irradiation by neutrons results in embrittlement of carbon and low-alloy steels. It may produce changes in mechanical properties by increasing tensile and yield strengths with a corresponding decrease in fracture toughness and ductility. The extent of embrittlement depends on neutron fluence, temperature, and trace material chemistry. [Ref. 26]
Ohmic heating	Ohmic heating is induced by current flow through a conductor and can be calculated using first principles of electricity and heat transfer. Ohmic heating is a thermal stressor and can be induced by conductors passing through electrical penetrations, for example. Ohmic heating is especially significant for power circuit penetrations. [Ref. 17]
Outside diameter stress corrosion cracking	Outside diameter stress corrosion cracking (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 PWSCC, which describes inner diameter (SG primary side) initiated cracking. [Ref. 23]. The primary loop basically consists of the reactor vessel, reactor coolant pumps, pressurizer steam generator tubes, and interconnecting piping.
Overload	Overload is one of the aging mechanisms that can cause loss of mechanical function in Class 1 piping and components, such as constant and variable load spring hangers, guides, stops, sliding surfaces, and vibration isolators, fabricated from steel or other materials, such as Lubrite®.
Oxidation	Oxidation involves two types of reactions: (a) an increase in valence resulting from a loss of electrons, or (b) a corrosion reaction in which the corroded metal forms an oxide. [Ref. 27]

IX.F Use of Terms for Aging Mechanisms

Term	Usage in this document
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	Primary water stress corrosion cracking (PWSCC) is an intergranular cracking mechanism that requires the presence of high applied and/or residual stress, susceptible tubing microstructures (few intergranular carbides), and also high temperatures. This aging mechanism is most likely a factor for nickel alloys in the PWR environment. [Ref. 22]
Radiation hardening, temperature, humidity, sustained vibratory loading	Reduction or loss of isolation function in polymeric vibration isolation elements can result from a combination of radiation hardening, temperature, humidity, and sustained vibratory loading.
Radiation-induced oxidation	Two types of reactions that are affected by radiation are (a) an increase in valence resulting from a loss of electrons, or (b) 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 MEB insulation. [Ref. 27]
Radiolysis	Radiolysis is a chemical reaction induced or assisted by radiation. Radiolysis and photolysis aging mechanisms can occur in UV-sensitive organic materials.
Reaction with aggregate	The presence of reactive alkalis in concrete can lead to subsequent reactions with aggregates that may be present. These alkalis are introduced mainly by cement, but also may come from admixtures, salt-contamination, seawater penetration, or solutions of deicing salts. These reactions include alkali-silica reactions, cement-aggregate reactions, and aggregate-carbonate reactions. These reactions may lead to expansion and cracking. [Ref. 14, 34]
Recurring internal corrosion	Recurring internal corrosion is identified by both the number of occurrences of internal aging effects with the same aging mechanism and the extent of degradation at each localized site. In regard to the number of occurrences, aging effects are considered recurring if the search of plant-specific 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. In regard to the extent of degradation, aging effects are considered recurring if the aging effect resulted in the component not meeting either plant-specific acceptance criteria or experiencing a reduction in wall thickness of greater than 50 percent (regardless of the minimum wall thickness). Recurring internal corrosion is evaluated based on the aging mechanisms observed. For example, multiple occurrences of LOM due to microbiologically-induced corrosion, LOM due to pitting, or LOM due to 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 also known as dealloying (e.g., dezincification or graphitic corrosion) and

IX.F Use of Terms for Aging Mechanisms

Term	Usage in this document
	involves selective corrosion of one or more components of a solid solution alloy.
Service-induced cracking or other concrete aging mechanisms	Cracking of concrete under load over time of service (e.g., from shrinkage or creep, or other concrete aging mechanisms) that may include freeze-thaw, leaching, aggressive chemicals, reaction with aggregates, corrosion of embedded steels, elevated temperatures, irradiation, abrasion, and cavitation. [Ref. 20]
Settlement	This term is referenced as an aging mechanism in GALL-SLR Chapter II, *Containment Structures*. Settlement of a containment structure may occur due to changes in the site conditions (e.g., water table, etc.). The amount of settlement depends on the foundation material. [Ref. 23]
Stress corrosion cracking	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 temperature. SCC is highly chemically specific in that certain alloys are likely to undergo SCC only when exposed to a small number of chemical environments. For PWR internal components, in Chapters IV.B2, IV.B3 and IV.B4, SCC includes intergranular SCC, transgranular SCC, primary water SCC, and low temperature crack propagation as aging mechanisms.
Stress relaxation	Many of the bolts in reactor internals are stressed to a cold initial preload. When subject to high operating temperatures, over time these bolts may loosen and the preload may be lost. Radiation can also cause stress relaxation in highly stressed members such as bolts. [Ref. 15]. Relaxation in structural steel anchorage components can be an aging mechanism contributing to the aging effect of loss of prestress.
Surface contamination	Contamination of the surfaces by corrosive constituents or fouling.
Sustained vibratory loading	Vibratory loading over time.
Thermal aging embrittlement	Also termed “thermal aging” or “thermal embrittlement.” At operating temperatures of 260 °C to 343 °C [500 to 650 °F], CASS exhibit a spinoidal decomposition of the ferrite phase into ferrite-rich and chromium-rich phases. This may give rise to significant embrittlement (reduction in fracture toughness), depending on the amount, morphology, and distribution of the ferrite phase and the composition of the steel. Thermal aging of materials other than CASS is a time- and temperature-dependent degradation mechanism that decreases material toughness. It includes temper embrittlement and strain aging embrittlement. Ferritic and low-alloy steels are subject to both of these types of embrittlement, but wrought SS is not affected by either of these processes. [Ref. 26]
Thermal effects, gasket creep, and self-loosening	Loss of preload due to gasket creep, thermal effects (including differential expansion and creep or stress relaxation), and self-loosening (which includes vibration, joint flexing, cyclic shear loads, thermal cycles). [Ref. 18, 19]
Thermal and mechanical loading	Loads (stress) due to mechanical or thermal (temperature) sources.
Thermal degradation of organic materials	Organic materials, in this case, are polymers. This category includes both 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 such aging effects as increased

IX.F Use of Terms for Aging Mechanisms

Term	Usage in this document
	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.
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 inducing 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 (RT or UT) techniques.
Thermoxidative degradation of organics/thermoplastics	Degradation of organics/thermoplastics via oxidation reactions (loss of electrons by a constituent of a chemical reaction) and thermal means (see Thermal degradation of organic materials). [Ref. 25]
Transgranular stress corrosion cracking	Transgranular stress corrosion cracking (TGSCC) is SCC in which cracking occurs across the grains.
Void swelling	Vacancies created in reactor (metallic) materials as a result of irradiation may accumulate into voids that may, in turn, lead to changes in dimensions (swelling) of the material. Void swelling may occur after an extended incubation period.
Water trees	Water trees occur when the insulating materials are exposed to long-term electrical stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. The growth and propagation of water trees is somewhat unpredictable. Water treeing is a degradation and long-term failure phenomenon.
Wear	Wear is defined as the removal of surface layers due to relative motion between two surfaces or under the influence of hard, abrasive particles. Wear occurs in parts that experience intermittent relative motion, frequent manipulation, or in clamped joints where relative motion is not intended, but may occur due to a loss of the clamping force. [Ref. 26]. Loss of material due to wear can also occur in polymeric components buried in soil containing deleterious materials that move over time due to seasonal change effects on the soil.
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.

G. REFERENCES

1. SNL. SAND 93–7070, “Aging Management Guideline for Commercial Nuclear Power Plants-Heat Exchangers.” Albuquerque, New Mexico: Sandia National Laboratories. June 1994.

2. ASTM International. “Corrosion: Materials, Corrosion of Copper and Copper Alloys.” Volume 13B. pp 129–133. Materials Park, Ohio: American Society for Testing Materials International. 2006.

3. ASME Boiler & Pressure Vessel Code, Section II: Part B, Nonferrous Material Specifications.

4. ASME Boiler & Pressure Vessel Code, Section II: Part A, Ferrous Material Specification.

5. NRC. NUREG–1950, “Disposition of Public Comments and Technical Bases for Changes in the License Renewal Guidance Documents NUREG–1801 and NUREG–1800.” Washington, DC: U.S. Nuclear Regulatory Commission. April 2011.

6. Welding Handbook. “Metals and Their Weldability.” Seventh Edition. Volume 4. American Welding Society. p. 76–145. 1984.

7. Metals Handbook. “Failure Analysis.” Ninth Edition. Volume 11. ASM International. p. 415. 1980.

8. Fink, F.W. and W.K. Boyd. “The Corrosion of Metals in Marine Environments.” DMIC Report 245. May 1970.

9. Gillen, K.T. and R.L. Clough. “Occurrence and Implications of Radiation Dose-Rate Effects for Material Aging Studies.” Radiation Physics and Chemistry. Vol. 18. p. 679. 1981.

10. Peckner, D. and I.M. Bernstein, eds. *Handbook of Stainless Steels*. McGraw-Hill. New York. p. 16–85. 1977.

11. EPRI. EPRI-1010639, “Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools,” Electric Power Research Institute, Palo Alto, California: pp. 2–13. January 2006.

12. Chopra, O.K. and A. Sather. ANL-89/17, “Initial Assessment of the Mechanisms and Significance of Low-Temperature Embrittlement of Cast Stainless Steels in LWR Systems.” Argonne, Illinois: Argonne National Laboratory. August 1990.

13. NRC. NUREG–1557, “Summary of Technical Information and Agreements from Nuclear Management and Resources Council Industry Reports Addressing License Renewal.” Washington, DC: U.S. Nuclear Regulatory Commission. October 1996.

14. Freeze, R.A. and J.A Cherry. *Groundwater*. Englewood Cliffs, New Jersey. Prentice-Hall. 1979.

15. NRC. NUREG–1760, “Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. May 2002.

16. JM Eagle™ Technical Bulletin. “The Effects of Sunlight Exposure on PVC Pipe and Conduit.” Ft. Recovery, Ohio: JM Manufacturing Company Inc. January 2009.

17. SNL. SAND96–0344, “Aging Management Guideline for Commercial Nuclear Power Plants-Electrical Cable and Terminations.” Albuquerque, New Mexico: Sandia National Laboratories. September 1996.

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

19. EPRI. EPRI NP-5067, “Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel.” Volume 1: “Large Bolt Manual.” 1987 and Volume 2: “Small Bolts and Threaded Fasteners.” 1990.

20. NRC. NUMARC Report 90-06, “Class 1 Structures License Renewal Industry Report.” Revision 1. Washington DC: U.S. Nuclear Regulatory Commission. December 1991.

21. NRC. GL 96-04, “Boraflex Degradation in Spent Fuel Pool Storage Racks.” Washington, DC: U.S. Nuclear Regulatory Commission. 1996.

22. Shah, V.N. and D. E. Macdonald, eds. “Aging and Life Extension of Major Light Water Reactor Components.” Amsterdam, Netherlands: Elsevier. 1993.

23. Gavrilas, M., P. Hejzlar, N.E. Todreas, and Y. Shatilla. “Safety Features of Operating Light Water Reactors of Western Designs.” Cambridge, Massachusetts. CANES, MIT. 2000.

24. NRC. NUMARC Report 90-01, “Pressurized Water Reactors Containment Structures License Renewal Industry Report.” Revision 1. Washington DC: U.S. Nuclear Regulatory Commission. 1991.

25. ASTM. “1976 Annual Book of ASTM Standards, Part 10.” Philadelphia, Pennsylvania: ASTM. 1976.

26. NRC. NUMARC Report 90-07, “PWR Reactor Coolant System License Renewal Industry Report,” Washington DC: U.S. Nuclear Regulatory Commission. May 1992.

27. Davis, J.R., Ed. “Corrosion.” Materials Park, Ohio: ASM International. 2000.

28. ASTM. “2004 Annual Book of ASTM Standards.” Volume 09.01. Philadelphia, Pennsylvania: ASTM International. 2004.

29. NRC. NUMARC Report 90-05, “PWR Reactor Pressure Vessel Internals License Renewal Industry Report.” Revision 1. Washington DC: U.S. Nuclear Regulatory Commission. December 1992.

30. EPRI. NSAC-202L-R4, “Recommendations for an Effective Flow-Accelerated Corrosion Program.” Palo Alto, California: Electric Power Research Institute. November 2013.

31. ACI. ACI 301-84, “Specification for Structural Concrete for Buildings.” (Field Reference Manual). Detroit, Michigan: American Concrete Institute. Revised 1988.

32. DNC. "Relief Request RR-04-13 for the Temporary Non-Code Compliant Condition of the Class 3 Service Water System 10-Inch Emergency Diesel Generator Supply Piping Flange." ML12297A333. Dominion Nuclear Connecticut, Inc. October 18, 2012.

33. EPRI. EPRI Report No 1000975, "Boric Acid Corrosion Guidebook, Revision 1: Managing Boric Acid Corrosion Issues at PWR Power Stations." Palo Alto, California: Electric Power Research Institute. 2001.

34. ACI. ACI 201.2R 77, "Guide to Durable Concrete." Detroit, Michigan: American Concrete Institute. Reapproved 1982.

CHAPTER X

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

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

This chapter of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report provides the following aging management programs (AMPs) that are used to demonstrate acceptance of specific types of generic time-limited aging analyses (TLAAs) in accordance with the requirements in 10 CFR 54.21(c)(1)(iii) 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 (SLR) period:

X.M1	CYCLIC LOAD MONITORING
X.M2	NEUTRON FLUENCE MONITORING
X.S1	CONCRETE CONTAINMENT UNBONDED TENDON PRESTRESS
X.E1	ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRIC COMPONENTS
TABLE X-01	FSAR SUPPLEMENT SUMMARIES FOR GALL-SLR REPORT CHAPTER X AGING MANAGEMENT PROGRAMS
TABLE X-02	FSAR SUPPLEMENT SUMMARIES FOR GALL-SLR REPORT AGING MANAGEMENT PROGRAMS DISCUSSED IN SRP-SLR CHAPTER 4

X.M1 CYCLIC LOAD MONITORING

Program Description

This aging management program (AMP) provides an acceptable basis for managing SCs that are the subject of fatigue or cycle-based time-limited aging analyses (TLAAs) or other analyses that assess fatigue or cyclical loading, in accordance with the requirements in 10 CFR 54.21(c)(1)(iii). Examples of cycle-based fatigue analyses for which this AMP may be used include, but are not limited to: (a) 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 (ASME) design code requirements for specific mechanical or structural components; (b) fatigue analysis calculations for assessing environmentally-assisted fatigue; (c) implicit fatigue analyses, as defined in the USAS B31.1 design code or ASME Section III rules for Class 2 and Class 3 components; (d) fatigue flaw growth analyses that are based on cyclical loading assumptions; (e) fracture mechanics analyses that are based on cycle-based loading assumptions; and (f) 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 (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 the other 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 severity of each transient remains 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. 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 not to exceed the design limit on CUF, the AMP monitors and tracks the number of occurrences of each of the critical thermal and pressure transients for the selected components, and verifies that the severity of each of the monitored transients is bounded by the design transient definitions.

CUF_{en} is CUF adjusted to account for the effects of the reactor water environment on component fatigue life. For a plant, the effects of reactor water environment on fatigue are evaluated by assessing a set of sample critical components for the plant. Examples of critical components are identified in NUREG/CR–6260; however, plant-specific component locations in the reactor coolant pressure boundary may be more limiting than those considered in

NUREG/CR–6260, and thus should also be considered. Environmental effects on fatigue for these critical components may be evaluated using the guidance in Regulatory Guide (RG) 1.207, Revision 1. Similar to monitoring of CUF limits, the AMP monitors and tracks the number of occurrences and 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 Report (GALL-SLR Report) AMP XI.M2, "Water Chemistry," to provide monitoring of appropriate environmental parameters for calculating environmental fatigue multipliers (F_{en} values).

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

In some cases, flaw tolerance evaluations are used to establish inspection frequencies for components that, for example, exceed CUF or CUF_{en} fatigue limits. As an example, ASME Code, Section XI, Nonmandatory Appendix L provides guidance on the performance of fatigue flaw tolerance evaluations to determine 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 provide guidance on the performance of fatigue flaw crack growth evaluations to determine acceptability for continued service of reactor coolant system pressure boundary components and piping subjected to cyclic loadings. 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 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 those 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 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, thus minimizing the likelihood of failures from fatigue-induced cracking of the components caused by cyclic strains in the component's material. In addition, the program can be used to monitor actual plant operating conditions to perform updated evaluations of the fatigue analyses to ensure they continue to meet the design limits.

For the purposes of ascertaining the effects of the reactor water environment on fatigue, applicants include CUF_{en} calculations for a set of sample reactor coolant system components. This sample set includes the locations identified in NUREG/CR–6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR–6260.

Component locations within the scope of this program are updated based on operating experience, 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 appropriate environmental parameters that contribute to F_{en} values. The number of occurrences, the severity of the plant transients, and actual plant water chemistry that contribute to the fatigue analyses for each component are monitored. 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 transients, and water chemistry conditions. 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 is 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 water chemistry conditions is used to ensure calculated F_{en} values remain valid. 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, thus 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   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 Section XI is an acceptable correction action. For CUF_{en} analyses, scope expansion includes consideration of other locations with the highest expected CUF_{en} values.

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

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

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

References

10 CFR Part 50, Appendix B. “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. “Rules for Construction of Nuclear Power Plant Components.” Boiler and Pressure Vessel Code, Section III. New York, New York: ASME. 2015.

_____. “Rules for Construction of Nuclear Facility Components.” ASME Code, Section III. New York, New York: ASME. 2015.

_____. “Rules for Inservice Inspection of Nuclear Power Plant Components.” ASME Code, Section XI, Nonmandatory Appendix A, Analysis of Flaws. New York, New York: ASME. 2015.

_____. “Rules for Inservice Inspection of Nuclear Power Plant Components.” ASME Code, Section XI, Appendix C, Evaluation of Flaws in Austenitic Piping. New York, New York: ASME. 2015.

_____. “Rules for Inservice Inspection of Nuclear Power Plant Components, Nonmandatory Appendix L, Operating Plant Fatigue Assessment.” ASME Code, Section XI. New York, New York: American Society of Mechanical Engineers. 2013

ANSI. ANSI/ASME B31.1, “Power Piping.” New York, New York: American National Standards Institute. 2014.

NRC. NUREG/CR–6909, “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials.” Revision 1. Washington, DC: U.S. Nuclear Regulatory Commission. March 2014.

_____. Regulatory Guide 1.207, “Guidelines for Evaluating the Effects of Light Water Reactor Coolant Environments in Fatigue Analyses of Metal Components.” Revision 1. Washington, DC: U.S. Nuclear Regulatory Commission. November 2014.

_____. “Metal Fatigue Analysis Performance by Computer Software.” NRC Regulatory Issue Summary 2011-14. Washington, DC: U.S. Nuclear Regulatory Commission. December 29, 2011.

_____. “Fatigue Analysis of Nuclear Power Plant Components.” NRC Regulatory Issue Summary 2008-30. Washington, DC: U.S. Nuclear Regulatory Commission. December 16, 2008.

_____. NUREG/CR–6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1995.

X.M2 NEUTRON FLUENCE MONITORING

Program Description

This aging management program (AMP) provides an acceptable basis for managing neutron fluence-based time-limited aging analysis (TLAAs) in accordance with requirements in 10 CFR 54.21(c)(1)(iii). This program monitors neutron fluence for reactor pressure vessel (RPV) components and reactor vessel internal (RVI) components and is used in conjunction with the guidance in Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) AMP XI.M31, “Reactor Vessel 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 location of 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.

The assessment of neutron fluence is an input to a number of RPV irradiation embrittlement analyses that are mandated by specific regulations in 10 CFR Part 50. 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 Subsequent License Renewal (SRP-SLR) Section 4.2, “Reactor Vessel Neutron Embrittlement Analyses.” The neutron irradiation embrittlement TLAAs that are managed by this AMP include, but are not limited to: (a) neutron fluence, (b) pressurized thermal shock (PTS) analyses for pressurized water reactors (PWRs), as mandated by 10 CFR 50.61 or alternatively [if applicable for the current licensing basis (CLB)] by 10 CFR 50.61a; (c) RPV upper-shelf energy (USE) analyses, as mandated by Section IV.A.1 of 10 CFR Part 50, Appendix G, and (d) pressure-temperature (P-T) limit analyses that are mandated by Section IV.A.2 of 10 CFR Part 50, Appendix G and controlled by plant Technical Specifications (TS) update 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 into a pressure-temperature limits report (PTLR).

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: (a) determination of the RPV beltline as defined in Regulatory Issue Summary (RIS) 2014-11, “Information On Licensing Applications For Fracture Toughness Requirements For Ferritic Reactor Coolant Pressure Boundary Components,” (b) 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 (c) evaluating 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, “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 to calculate 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, nor 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 those 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. The implementation of such dosimetry capsules may be needed when the reactor surveillance program has exhausted the available capsules for in-vessel exposure.

Evaluation and Technical Basis

1. ***Scope of Program***: The scope of the program includes RPV and RVI components that are subject to a neutron embrittlement TLAA or other analysis involving time-dependent neutron irradiation. The program monitors neutron fluence throughout the subsequent period of extended operation for determining the susceptibility of the components to IE, IASCC, IESRC, and void swelling or distortion. The program also continues to ensure the adequacy of the neutron fluence estimates by: (a) monitoring plant and core operating conditions relative to the assumptions used in the neutron fluence calculations, and (b) 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 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, and if appropriate, plant Technical Specifications (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 thus there are no specific preventive actions. Because this program can be used to ensure 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. Since the program is used to ensure 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***: The 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 ensure the adequacy of neutron fluence calculations. Neutron fluence levels in specific components are monitored to ensure component locations within the scope of this program are identified.

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

Guidance on acceptable methods and assumptions for determining RPV neutron fluence is described in NRC RG 1.190. The use of RG 1.190-adherent methods to estimate neutron fluence for the RPV beltline regions significantly above and below the active field region of the core, and 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 is 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 field 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 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 relate to the different parameters that are evaluated using neutron fluence, as described in SRP-SLR Section 4.2.

   NRC RG 1.190 provides guidance for acceptable methods to determine neutron fluence for the RPV beltline region. It should be noted, 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.

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

   The program provides for corrective actions by updating the analyses for the RPV components, or assessing the need for revising 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 to 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 mandated 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 those specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

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

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL Report.

References

10 CFR Part 50, Appendix B. "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, "Codes and Standards." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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. 2015.

10 CFR 50.61. "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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, Appendix G. "Fracture Toughness Requirements." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR Part 50, Appendix H. "Reactor Vessel Material Surveillance Program Requirements." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

NRC. NRC Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." ML010890301 Washington, DC: U.S. Nuclear Regulatory Commission. March 2001.

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). 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 (ASME) Code, Section XI, as incorporated by reference in 10 CFR 50.55a, 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 (a) acceptance criteria in accordance with ASME Section XI, Subsection IWL and (b) trend lines constructed based on the guidance provided in the U.S. Nuclear Regulatory Commission (NRC) Information Notice (IN) 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments." The NRC Regulatory Guide (RG) 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments," may be used for guidance related to calculation of prestressing losses and predicted forces.

Evaluation and Technical Basis

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

2. ***Preventive Actions***: This is primarily a condition monitoring program, which 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 Section XI, Subsection IWL. The prestressing forces are measured on common (control) tendons and tendons selected by random sampling of each tendon group using 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 analyzing (predicting) tendon forces and trending the data obtained as part of ASME Section XI, Subsection IWL examinations.

5. ***Monitoring and Trending***: In addition to Subsection IWL examination requirements, the estimated and all measured prestressing forces up to the current examination are plotted against time. The predicted lower limit (PLL) line, MRV, and trend line are developed for each tendon group examined for the subsequent period of extended operation. The trend line represents the general variation of prestressing forces with time based on the actual measured forces in individual tendons of the specific tendon

group. The trend line for each tendon group is constructed by regression analysis of all measured prestressing forces in individual tendons of that group obtained from all previous examinations. The PLL line, MRV, and trend line for each tendon group are projected to the end of the subsequent period of extended operation. The trend lines are updated at each scheduled examination.

6. ***Acceptance Criteria***: The prestressing force trend line (constructed as indicated in 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

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

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

   The confirmation process ensures that condition monitoring leads to preventive actions that are adequate and appropriate, and that required corrective actions have been completed and are effective.

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

10. ***Operating Experience***: The program incorporates a review of the relevant operating experience that has occurred at the applicant's plant as well as at other plants. NUREG/CR–7111, "A Summary of Aging Effects and their Management in Reactor

Spent Fuel Pools, Refueling Cavities, Tori, and Safety-Related Concrete Structures," summarizes observations on low prestress forces recorded in some plants. However, tendon operating experience may vary at different plants with 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 (PWR) and boiling water reactor (BWR)] and possible concrete containment modifications. Thus, the applicant's plant-specific operating experience is reviewed and evaluated in detail for the subsequent period of extended operation. Applicable portions of the experience with prestressing systems described in NRC IN 99-10 could be useful.

If plant-specific operating experience 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 operating experience.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experiences, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B. "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a. "Codes and Standards." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 54.21. "Contents of Application-Technical Information." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

American Society of Mechanical Engineers. "Boiler and Pressure Vessel Code." Section XI, Subsection IWL, "Requirements for Class CC Concrete Components of Light-Water Cooled Plants." New York, New York. ASME. 2015.

NRC. NUREG/CR-7111, "A Summary of Aging Effects and their Management in Reactor Spent Fuel Pools, Refueling Cavities, Tori, and Safety-Related Concrete Structures." ML12047A184. Washington, DC: U.S. Nuclear Regulatory Commission. January 2012.

_____. "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments." Information Notice 99-10. ML031500244. Washington DC: U.S. Nuclear Regulatory Commission. April 1995.

_____. "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments." Regulatory Guide 1.35.1. ML003740040. Washington DC: U.S. Nuclear Regulatory Commission. July 1990.

X.E1 ENVIRONMENTAL QUALIFICATION OF ELECTRIC COMPONENTS

Program Description

The U.S. Nuclear Regulatory Commission (NRC) has established nuclear station environmental qualification (EQ) requirements in 10 CFR Part 50, 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, those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line break (HELB) and post-LOCA environment are qualified to perform their safety function 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.

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

For equipment located in a mild environment (an environment that at no time would be significantly more severe than the environment occurring during normal operation, including anticipated operational occurrences as defined in 10 CFR 50.49), the demonstration that the equipment can meet 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 certificate of conformance.

Operating plants requesting subsequent license renewal shall meet the qualification requirements of 10 CFR 50.49 and license renewal aging management provisions of 10 CFR Part 54 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, and requires the preparation and maintenance of a qualification file that contains the qualification report, with applicable equipment performance specifications, electrical characteristics, and the environmental conditions to which the equipment could be subjected. Licensees are required to maintain a record of qualification in auditable form [10 CFR 50.49(j)] for the entire period during which each covered item installed in the nuclear power plant or is stored for future use.

Additionally, 10 CFR 50.49(e) states that electric equipment qualification programs must include and be based on temperature, pressure, humidity, chemical effects, radiation, aging, submergence, and synergistic effects. The requirements of 10 CFR 50.49(e) also includes the application of margins to account for unquantified uncertainties, including production variations, and in accuracies 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. Aging provisions contained in 10 CFR 50.49(e)(5) contains provisions for preconditioning equipment to its end-of-installed life condition that requires, in part, consideration of all significant types of aging degradation (e.g., thermal, radiation, vibration, plant specific operational aging, and cyclic aging) that can affect the function of electrical equipment. For equipment preconditioned to less than an end-of-installed life condition (i.e., designated life) 10 CFR 50.49(e)(5) requires the equipment to be replaced or refurbished at the end of its designated life unless additional life is established through reanalysis or ongoing qualification.

Four methods are established by 10 CFR 50.49(f) to demonstrate qualification for aging and accident conditions. Additionally 10 CFR 50.49(k) and (i) permit different qualification criteria to apply based on plant and electrical equipment vintage.

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

EQ programs manage equipment aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ equipment not qualified for the current license term are refurbished, replaced, or have their 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 40 to 60 years are considered time-limited aging analysis (TLAAs) for subsequent license renewal (SLR).

Under 10 CFR 54.21(c)(1)(iii), plant EQ programs, which implement the requirements of 10 CFR 50.49 (as further defined and clarified by the DOR Guidelines, NUREG–0588, and RG 1.89, Rev. 1) along with GALL-SLR Report AMP X.E1 used to demonstrate acceptability of the TLAA analysis under 10 CFR 54.21(c)(1) are considered AMPs for license renewal.

Reanalysis of an aging evaluation to extend the qualification of equipment qualified under the program requirements of 10 CFR 50.49(e) 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 (if acceptance criteria are not met). These attributes are discussed in the “EQ Equipment Reanalysis Attributes” section.

Extension of equipment environmental qualification (qualified life) for the subsequent period of extended operation may be accomplished through the following: (1) 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, (2) removal and type-testing of additional EQ equipment installed in identical service conditions with a greater period of operational aging, (3) evaluation of original attributes, assumptions and conservatisms for environmental conditions and other factors (reanalysis) that allow equipment qualified life to be increased or (4) replacement.

This reanalysis can be applied to EQ equipment now qualified for the current operating term (i.e., equipment qualified for 60 years). As evaluated below, an existing EQ program incorporating a reanalysis program, consistent with Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management programs (AMP) X.E1 is an acceptable AMP. Thus, no further evaluation is recommended for subsequent license renewal (SLR) if an applicant’s EQ program supports this option under 10 CFR 54.21(c)(1)(iii) to evaluate the TLAA of EQ of electrical equipment and the reanalysis shows that a 80-year qualification is established prior to the plant entering the subsequent period of extended operation.

As is required by 10 CFR 50.49(j) for the initial environmental qualification, a record of the qualification must be maintained in an auditable form for the entire subsequent period of extended operation during which the covered item is installed in the nuclear power plant (NPP) or is stored for future use. This permits verification that each item of electric equipment important to safety covered by this section is (a) qualified for its application and (b) meets its specified performance requirements when it is subjected to the conditions predicted to be present and when it must perform a safety function up to the end of qualified life.

Environmental Qualification Equipment Reanalysis Attributes

The reanalysis of an aging evaluation is normally performed to extend the qualification by reevaluating original attributes, assumptions and conservatisms in environmental conditions and other factors to identify excess conservatisms incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of electrical equipment is performed pursuant to 10 CFR 50.49(e) as part of an EQ program. While an electrical equipment life limiting condition may be due to thermal, radiation, or cyclical aging, the majority of electrical equipment aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed service conditions [environmental–including temperature and radiation, loading, power, signal conditions, cycles, and application (e.g., deenergized versus energized)], or an unrealistically low activation energy. The reanalysis of an aging evaluation is performed according to the station's quality assurance (QA) program requirements, which requires 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 (if acceptance criteria are not met). 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 is, normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, one acceptable method of establishing the 80-year normal radiation dose is to multiply the initial 40-year normal radiation dose by 2.0 (that is, 80 years/40 years). 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 and uncertainties used in an equipment EQ evaluation may be based on anticipated plant design temperatures found to be conservative when compared to actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance; other installed monitors, measurements made by plant operators during rounds, or dedicated monitoring equipment for EQ.

A representative number of temperature measurements over a sufficient period of time are evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as (a) directly applying the plant temperature data in the evaluation or (b) using the plant temperature data to demonstrate conservatism when using plant design temperatures for an evaluation. The methodology for environmental monitoring, data collection and the analysis of localized EQ equipment environmental data (including temperature and radiation) used in the reanalysis is justified in the record of the reanalysis qualification report.

Environmental monitoring data used in the analysis that is collected one time, or is of limited duration, is justified with respect to the applicability of such data to the reanalysis. Any changes to material activation energy values included as part of a reanalysis are justified by the applicant on a plant-specific basis. Similar methods of identifying excess conservatism in the equipment service condition evaluation can be used for radiation and cyclical aging.

***Underlying Assumptions**:* EQ equipment aging evaluations account for environmental changes occurring due to plant modifications and events. A reanalysis demonstrates that adequate margin is maintained consistent with the original analysis in accordance with 10 CFR 50.49 requiring certain margins and accounting for the unquantified uncertainties established in the EQ aging evaluation of the equipment. Reanalysis that utilizes initial qualification conservatisms and/or in-service environmental conditions (e.g., actual temperature and radiation conditions) are part of an EQ program.

In areas within a NPP, the actual ambient environments (e.g., temperature, radiation, or moisture) may be less severe than the anticipated plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment. These localized areas are characterized as adverse localized environments that represent conditions in a limited plant area that are significantly more severe than the plant design environment considered for EQ equipment (e.g., cable or connection insulation material). Adverse localized environments are addressed in an EQ reanalysis.

An adverse localized environment may increase the rate of aging of a component 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, radiation, or moisture for the component material (e.g., cable or connection insulation). Accessible electrical EQ equipment is visually inspected and the equipment environment evaluated to identify in-scope electrical equipment subjected to an adverse localized environment. EQ equipment is evaluated to assess the impact of the adverse localized environment on equipment EQ including qualified life.

Adverse localized environments are identified through the use of an integrated approach. This approach includes but is not limited to, (a) the review of EQ zone maps that show radiation levels and temperatures for various plant areas, (b) recorded information from equipment or plant instrumentation, (c) plant spaces scoping and screening,(d) as-built and field walk down data, and (e) the review of relevant plant-specific and industry operating experience including:

- Review of maintenance procedures for work practices that may subject in-scope EQ equipment to an “adverse localized environment.”

- Review corrective actions applicable to in-scope EQ equipment (e.g., cables and connections electrical insulation material) previously subjected to an adverse localized environment that could affect the functional capability of the equipment during SLR (e.g., equipment disposition based on current operating term).

- Visual inspection of equipment and environmental monitoring (e.g., periodic environmental monitoring) of accessible EQ equipment including, as appropriate, EQ equipment identified by (a, b, c, d, and e above).

Accessible electrical EQ equipment is visually inspected and the EQ equipment environment evaluated every 10 years to identify in-scope electrical equipment subjected to an adverse localized environment and evaluate the impact on EQ electrical equipment including qualified life. The first periodic inspection is to be performed prior to the subsequent period of extended operation.

The periodic visual inspection is specifically intended to address EQ electrical equipment where most if not all equipment subjected to an adverse localized environment is accessible. EQ equipment from accessible areas is inspected and the applicant shows that it represents, with reasonable assurance, all in-scope EQ equipment in the adverse localized environment. 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 to the qualified life.

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 the current qualified life. A reanalysis is performed in a timely manner (that is, sufficient time is available to refurbish, replace, or requalify the equipment if the result is unfavorable).

Ongoing Qualification*:* As an alternative to reanalysis when assessed margins, conservatisms, or assumptions do not support extending qualified life, the use of ongoing qualification techniques including condition monitoring or condition based methodologies may be implemented as a means to provide reasonable assurance that equipment environmental qualification (qualified life), is maintained for the subsequent period of extended operation. Ongoing qualification of electric equipment important to safety subject to the requirements of 10 CFR 50.49 involves the inspection, observation, measurement, or trending of one or more indicators, which can be correlated to the condition or functional performance of the EQ equipment.

Ongoing qualification techniques including condition based monitoring provide information that may be used in the determination of a component's ability to perform its safety function and remaining qualified life for the subsequent period of extended operation. Ongoing qualification techniques for EQ equipment include periodic testing, inspections, mitigation, and sampling (e.g., subsequent EQ qualification testing of inservice or representative EQ equipment with established acceptance criteria and corrective actions, mitigation, replacement or refurbishment) consistent with endorsed standards and regulatory guidance. A modification to qualified life either by reanalysis or ongoing qualification must demonstrate that adequate margin is maintained consistent with the original analysis including unquantified uncertainties established in the original EQ equipment ageing valuation.

Evaluation and Technical Basis

1. ***Scope of Program***: EQ programs apply to certain electrical equipment that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49 and RG 1.89, Rev.1.

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

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

4. ***Detection of Aging Effects***: 10 CFR 50.49 does not require the detection of aging effects for in-service equipment. EQ program actions that could be viewed as detection of aging effects including, (a) inspecting or testing equipment periodically with particular emphasis on condition assessment of equipment EQ including a 10 year periodic inspection of accessible in-scope EQ components to identify EQ components subject to an adverse localized environment and, (b) monitoring of plant environmental conditions or component parameters that are be used to ensure that the equipment is within the bounds of its environmental qualification basis including attributes, assumptions, and conservatisms for equipment/environmental conditions and other factors. Monitoring or inspection of certain environmental conditions or component parameters may also provide a means to assess equipment qualified life.

   The first periodic visual inspection is to be performed prior to the subsequent period of extended operation. Visual inspection (and the use of additional diagnostic tools such as thermography) of EQ components is performed as appropriate, by opening junction boxes, pull boxes, or terminal boxes. Scaffolding may be used if available. The purpose of the visual inspection is to identify adverse localized environments that may impact an EQ components qualified life. Potential adverse localized environments are evaluated through the applicant's corrective action program.

5. ***Monitoring and Trending***: 10 CFR 50.49 does not require monitoring and trending of component condition or performance parameters of in-service equipment to manage the effects of aging, but may be applicable to condition monitoring including condition based ongoing qualification methodologies. Monitoring, inspection, or trending may be used to ensure that equipment is within the bounds of its qualification basis, or as a means to modify the qualification (e.g., service life or qualified life).

   Specifically, a monitoring, inspection, or trending program used to ensure that electrical equipment is within the bounds of its qualification basis, or as a means to modify qualified life (e.g., programs for monitoring, inspection, or trending of environmental conditions (such as temperature, radiation, equipment condition or component parameters), may be implemented for EQ equipment). The monitoring and trending frequency is established and adjusted based on the results of EQ equipment monitoring, inspection, or trending.

6. ***Acceptance Criteria***: 10 CFR 50.49 acceptance criteria are that in-service EQ equipment is maintained within the bounds of its qualification basis, including (a) its established qualified life and (b) 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 device. 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.

7. ***Corrective Actions***: Results that do not meet the acceptance criteria are addressed as conditions adverse to quality or significant conditions adverse to quality under those 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 corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

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

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

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

   EQ programs are implemented through the use of station policy, directives, and procedures. EQ programs continue to comply with 10 CFR 50.49 throughout the subsequent period of extended operation, including development and maintenance of qualification documentation demonstrating reasonable assurance that electrical equipment can perform required functions during design basis accidents that result in harsh environment conditions. EQ program documents identify the applicable environmental conditions for the equipment locations. EQ program qualification files are maintained at the plant site in an auditable form for the duration of the installed life of the equipment or stored for future use. Program documentation is controlled under the station's QA program.

10. ***Operating Experience****:* EQ programs include consideration of operating experience to modify qualification bases and conclusions, including qualified life such that the impact on the EQ program is evaluated and any necessary actions or modifications to the program are performed. Compliance with 10 CFR 50.49 provides reasonable assurance that EQ equipment can perform their intended functions 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 operating experience, consistent with the discussion in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B. "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.49. "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 54.21. "Contents of Application—Technical Information." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. "Plant Support Engineering: License Renewal Electrical Handbook." EPRI Report 1003057. Revision 1. Palo Alto, California: Electric Power Research Institute February 2007.

IAEA. TECDOC1188, "Assessment and Management of Ageing of Major Nuclear Power Plant Components Important to Safety: In-Containment Instrumentation and Control Cables." ML15013A087. Vienna: International Atomic Energy Agency. 2015.

_____. IAEA D-NP-T.3.6, "Guideline for Qualification and Ageing Management of I&C Cables in Current and Future NPGS." ML15013A087. Vienna: International Atomic Energy Agency. 2015.

_____. NS-G-2.12, "Ageing Management for Nuclear Power Plants." Vienna: International Atomic Energy Agency. 2009.

IEEE. IEEE Std. 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.

JNSO. JNES-SS-0903, "The Final Report of the Project of "Assessment of Cable Aging for Nuclear Power Plants." Minato-ku, Tokyo: Japan Nuclear Safety Organization, Nuclear Energy Systems Safety Division. July 2009.

NRC. "Condition-Monitoring Techniques for Electric Cables Used in Nuclear Power Plants," Regulatory Guide 1.218. ML103510458. Washington DC: U.S. Nuclear Regulatory Commission. April 2012.

_____. NUREG/CR-7000, “Essential Elements of an Electric Cable Condition Monitoring Program.” ML100540050. Washington, DC: U.S. Nuclear Regulatory Commission. January 2010.

_____. “Qualification of Safety-Related Cables and Field Splices for Nuclear Power Plants.” Regulatory Guide 1.211. ML082530205. Washington, DC: U.S. Nuclear Regulatory Commission. April 2009.

_____. Generic Letter 2007-01, “Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients.” ML13098A126. Washington, DC: U.S. Nuclear Regulatory Commission. February 2007.

_____. “Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants.” Regulatory Guide 1.100, Rev. 3. ML091320468. Washington DC: U.S. Nuclear Regulatory Commission. September 2003.

_____. “Environmental Qualification of Low-Voltage Instrumentation and Control Cables.” Regulatory Issue Summary 2003-09. May 2003.

_____. “Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants.” Regulatory Guide 1.89. Rev. 1. ML14070A119. Washington, DC: U.S. Nuclear Regulatory Commission. June 1984.

_____. NUREG–0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment.” Revision 1. ML031480402. Washington, DC: U.S. Nuclear Regulatory Commission. July 1981.

_____. “Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors.” (DOR Guidelines) ML032541214. Washington, DC: U.S. Nuclear Regulatory Commission. November 1979.

OCED/NEA. “Technical Basis for Commendable Practices on Aging Management—SCC and Cable Aging Project (SCAP) Final Report.” Final Report, NEA/CSNI/R (2010)15. France: April 2011.

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

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
X.M1	Cyclic Load Monitoring	The aging management program monitors and tracks the number of occurrences and severity of each of the thermal and pressure transients and requires corrective actions to ensure that applicable fatigue analyses remain within their allowable limits, including those in applicable CUF analyses, CUF_{en} analyses, maximum allowable stress range reduction analyses for ANSI B31.1 and 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 manages cracking induced by fatigue or cyclic loading occurrences in plant structures and components by monitoring one or more relevant fatigue parameters, which include the CUF, the CUF_{en}, transient cycle limits, and the predicted flaw size. The program has two aspects, one to verify the continued acceptability of existing analyses through cycle counting and the other to provide periodically updated evaluations of the fatigue analyses to demonstrate that they continue to meet the appropriate limits. Plant technical specification requirements may apply to these activities.	Existing Program	GALL IV / SRP 4.3
X.M2	Neutron Fluence Monitoring	This program monitors and tracks increasing neutron fluence exposures (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).	SLR Program Should be Implemented Prior to the Subsequent Period of Extended Operation	GALL IV / SRP 4.3

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

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		Monitoring is performed in accordance with neutron flux determination methods and neutron fluence projection methods that are defined for the CLB in NRC-approved reports. For fluence monitoring activities that apply to components located in the beltline region of the reactor pressure vessel(s), the monitoring methods are performed in a manner that is consistent with the monitoring methodology guidelines in Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," March 2001. Additional justifications may be necessary for neutron fluence monitoring methods that are applied to reactor pressure vessel component 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 analyses, and low temperature overpressure protection (LTOP, PWRs only) that are required to be performed in accordance in 10 CFR Part 50, Appendix G requirements, and for PWRs, those safety analyses that are performed to demonstrate adequate protection of the reactor pressure vessels against the consequences of pressurized thermal shock (PTS) events, as required by 10 CFR 50.61 or 10 CFR 50.61a and applicable to the CLB. Comparisons to the neutron fluence inputs for other analyses (as applicable to the CLB) may include those for mean RT_{NDT} and probability of failure analyses for BWR reactor pressure vessel circumferential and axial shell welds, BWR core reflood design analyses, and aging effect assessments for PWR and		

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

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		BWR reactor internals that are induced by neutron irradiation exposure mechanisms. Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the applicant's Reactor Vessel Surveillance Program (Refer to GALL-SLR Report AMP XI.M31) may provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant technical specifications or in specific regulations of 10 CFR Part 50 may apply, including those in 10 CFR Part 50, Appendix G; 10 CFR 50.55a; and for PWRs, the PTS requirements in 10 CFR 50.61 or 10 CFR 50.61a, as applicable for the CLB.		
X.S1	Concrete Containment Tendon Prestress	The prestressing tendons are used to impart compressive forces in the prestressed concrete containments to resist the internal pressure inside the containment that would be generated in the event of a LOCA. The prestressing forces generated by the tendons diminish over time due to losses in prestressing forces in the tendons and in the surrounding concrete. The prestressing force analysis and evaluation has been completed and determined to remain within allowable limits to the end of the subsequent period of extended operation, and the trend lines of the measured prestressing forces will stay above the minimum required prestressing forces for each group of tendons to the end of this period.	Existing program	GALL II / SRP 4.5
X.E1	Environmental Qualification (EQ) of Electric Components	This program implements the environmental qualification (EQ) requirements in 10 CFR Part 50, 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 function in those harsh environments after the effects of in-service aging.		GALL VI / SRP 4.4

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

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification. As required by 10 CFR 50.49, EQ equipment not qualified for the current license term is refurbished, replaced, or have their 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 time-limited aging analyses (TLAAs) for subsequent license renewal. Reanalysis of an aging evaluation to extend the qualification of equipment qualified under the program requirements of 10 CFR 50.49(e) 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 (if acceptance criteria are not met). The analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. The identification of excess conservatism in electrical equipment service conditions (for example, temperature, radiation, and cycles) used in the prior aging evaluation is the chief method used for a reanalysis. A reanalysis demonstrates that adequate margin is maintained consistent with the original analysis in accordance with 10 CFR 50.49 requiring certain margins and accounting for the unquantified uncertainties established in the EQ aging evaluation of the equipment. Reanalysis of an aging evaluation is used to extend the environmental qualification of the component. If the qualification cannot be extended by reanalysis, the equipment is refurbished, replaced, or requalified prior to exceeding the current		

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

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		qualified life. When the reanalysis assessed margins, conservatisms, or assumptions do not support reanalysis (e.g., extending qualified life) of an EQ component, the use of on-going qualification techniques including condition monitoring or condition based methodologies may be implemented. Ongoing qualification is an alternative means to provide reasonable assurance that an equipment environmental qualification is maintained for the subsequent period of extended operation. Ongoing qualification of electric equipment important to safety subject to the requirements of 10 CFR 50.49 involves the inspection, observation, measurement, or trending of one or more indicators, which can be correlated to the condition or functional performance of the EQ equipment. This program is implemented in accordance 10 CFR 50.49 and 10 CFR 54.21(c)(1)(iii). Along with GALL-SLR Report AMP X.E1 the environmental qualification program demonstrates the acceptability of the TLAA analysis under 10 CFR 54.21(c)(1) and is considered an aging management program (AMP) for the subsequent period of extended operation. This 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 (e.g., test methods, aging models, acceptance criterion) such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report. [The FSAR Summary description also includes a plant		

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

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		specific discussion of applicable commitments, license conditions, enhancements, or exceptions applied to the applicants aging management program]		

Table X-02 FSAR Supplement Summaries for GALL-SLR Report Aging Management Programs Discussed in SRP-SLR Chapter 4

SRP-SLR Section	TLAA	Description of Evaluation	Implementation Schedule*
4.2	USE	10 CFR Part 50 Appendix G paragraph IV.A.1 requires that the reactor vessel beltline materials must maintain Charpy upper-shelf energy of no less than 50 ft-lb (68 J) throughout the life of the reactor vessel unless otherwise approved by the NRC. The upper-shelf energy has been determined to exceed 50 ft-lb (68 J) to the end of the period of extended operation.	Completed
4.2	Pressurized thermal shock (for PWRs)	For PWRs, 10 CFR 50.61 requires the “reference temperature RT_{PTS}” for reactor vessel beltline materials to be less than the “PTS screening criteria” at the expiration date of the operating license unless otherwise approved by the NRC. The “PTS screening criteria” are 270°F (132°C) for plates, forgings, and axial weld materials, or 300°F (149°C) for circumferential weld materials. The “reference temperature” has been determined to be less than the “PTS screening criteria” at the end of the period of extended operation.	Completed
4.2	P-T limits	10 CFR Part 50 Appendix G requires that heatup and cooldown of the RPV be accomplished within established P-T limits. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the RPV becomes embrittled and its fracture toughness is reduced, the allowable pressure is reduced. 10 CFR Part 50 Appendix G requires periodic update of P-T limits based on projected embrittlement and data from a material surveillance program. The P-T limits will be updated to consider the period of extended operation.	Update should be completed before the subsequent period of extended operation
4.2	Elimination of circumferential weld inspection and analysis of axial welds (for BWRs)	NRC has granted relief from the reactor vessel circumferential shell weld inspections because the applicant has demonstrated through plant-specific analysis that the plant meets the staff-approved BWRVIP-74-A Report and has provided sufficient information that the probability of vessel failure due to embrittlement of axial welds is low. If the applicant indicates that relief from circumferential weld examination will be made under 10 CFR 50.55a(a)(z), the applicant will manage this TLAA in accordance with 10 CFR 54.21(c)(1)(iii).	Resubmittal under 10 CFR 50.55a(a)(z) should be completed before the period of extended operation
4.2	Other miscellaneous TLAAs on RV neutron embrittlement	Provide sufficient information on how the calculations for plant-specific TLAAs were performed, what the limiting TLAA parameter was calculated to be in accordance with the neutron fluence projected for the period of extended operation, and why the TLAA is acceptable under either 10 CFR 54.21(c)(1)(i), (ii), or (iii).	
4.3	Components Evaluated for Fatigue Parameters Other than CUF_{en}	[Applicant to identify and provide adequate description of the specific metal fatigue parameter evaluation] The number of occurrences and severity of each of the thermal and pressure transients, projected to the end of the subsequent license renewal operating period, demonstrate that the [Applicant to insert Name of the TLAA] remains valid during	Completed (prior to submittal of an application for SLR)

Table X-02 FSAR Supplement Summaries for GALL-SLR Report Aging Management Programs Discussed in SRP-SLR Chapter 4

SRP-SLR Section	TLAA	Description of Evaluation	Implementation Schedule*
		the subsequent license renewal operating period and therefore, that this TLAA is acceptable in accordance with the criterion in 10 CFR 54.21(c)(1)(i).	
4.3	Components Evaluated for CUF_{en}	[Applicant to identify and provide adequate description of the specific metal fatigue evaluation for evaluating environmentally assisted fatigue in ASME Code Class 1 or Safety Class 1 components] The effects of the water environment on component fatigue life have been addressed by assessing the impact of the water environment on the limiting component locations, using the positions described in Regulatory Guide 1.207, Revision 1. The number of occurrences and severity of each of the thermal and pressure transients, projected to the end of the subsequent license renewal operating period, and consideration of the water chemistry parameters demonstrate that the TLAA on environmentally assisted fatigue remains valid during the subsequent license renewal operating period and therefore, that this TLAA is acceptable in accordance with 10 CFR 54.21(c)(1)(i).	Completed (prior to submittal of an application for SLR)
4.3	Components Evaluated for Fatigue Parameters Other than CUF_{en}	[Applicant to identify and provide adequate description of the specific metal fatigue parameter evaluation] The analysis has been projected to the end of the subsequent license renewal operating period, considering the number of occurrences and severity of each of the thermal and pressure transients, and demonstrates that the TLAA is acceptable in accordance with 10 CFR 54.21(c)(1)(ii).	Completed (prior to submittal of an application for SLR)
4.3	Components Evaluated for CUF_{en}	Applicant to identify and provide adequate description of the specific metal fatigue evaluation for evaluating environmentally assisted fatigue in ASME Code Class 1 or Safety Class 1 components] The effects of the water environment on component fatigue life have been addressed by assessing the impact of the water environment on the limiting component locations, using the positions described in Regulatory Guide 1.207, Revision 1. The analysis for environmentally-assisted fatigue has been projected to the end of the subsequent license renewal operating period, considering the number of occurrences and severity of each of the thermal and pressure transients and the	Completed (prior to submittal of an application for SLR)

Table X-02 FSAR Supplement Summaries for GALL-SLR Report Aging Management Programs Discussed in SRP-SLR Chapter 4

SRP-SLR Section	TLAA	Description of Evaluation	Implementation Schedule*
		water chemistry parameters, and demonstrates that the TLAA is acceptable in accordance with 10 CFR 54.21(c)(1)(ii).	
4.3	Components Evaluated for Fatigue Parameters Other than CUF_{en}	Fatigue evaluations were performed to ensure the continued validity of the metal fatigue analyses for the subsequent license renewal operating period. [Applicant to provide adequate description of the specific metal fatigue parameter evaluation] The aging management program monitors and tracks the number of occurrences and severity of thermal and pressure transients, and requires corrective actions to ensure that applicable fatigue analyses remain within their allowable limits. The effects of aging due to fatigue will be managed by the aging management program for the subsequent license renewal operating period in accordance with 10 CFR 54.21(c)(1)(iii).	Program should be implemented before the subsequent period of extended operation
4.3	Components Evaluated for CUF_{en}	The effects of the water environment on component fatigue life will be addressed by assessing the impact of the water environment on the limiting component locations, using the positions described in Regulatory Guide 1.207, Revision 1. A limiting sample of critical components can be evaluated by applying environmental adjustment factors to the existing CUF analyses or by performing more refined calculations. The aging management programs monitor and track the number of occurrences and severity of thermal and pressure transients, monitor water chemistry, and require corrective actions to ensure that the applicable fatigue analyses remain within their allowable limits. The effects of aging due to environmentally assisted fatigue will be managed by the aging management programs for the subsequent license renewal operating period in accordance with 10 CFR 54.21(c)(1)(iii).	Program should be implemented before the subsequent period of extended operation
4.4	Environmental qualification of electric equipment	The original environmental qualification qualified life has been shown to remain valid for the period of extended operation. [Plant specific identification and summary descriptions of commitments, license conditions, enhancements or exceptions are also described as applicable]	
4.4	Environmental qualification of electric equipment	The environmental qualification has been projected to the end of the period of	Completed

Table X-02 FSAR Supplement Summaries for GALL-SLR Report Aging Management Programs Discussed in SRP-SLR Chapter 4

SRP-SLR Section	TLAA	Description of Evaluation	Implementation Schedule*
		extended operation. [The summary report addresses the key reanalysis attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions]. [Plant specific identification and summary descriptions of commitments, license conditions, enhancements or exceptions are also described as applicable]	
4.4	Environmental qualification of electric equipment	The applicant's environmental qualification process, in accordance with 10 CFR 50.49, will adequately manage aging of environmental qualification equipment for the period of extended operation because equipment will be replaced prior to reaching the end of its qualified life. [The summary report addresses the key reanalysis attributes of methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions.] [The applicant states that its environmental qualification program contains the same elements evaluated in the GALL-SLR Report.] [Plant specific identification and summary descriptions of commitments, license conditions, enhancements or exceptions are also described as applicable]	Existing program
4.5	Concrete containment tendon prestress	The prestressing tendons are used to impart compressive forces in the prestressed concrete containments to resist the internal pressure inside the containment that would be generated in the event of a LOCA. The prestressing forces generated by the tendons diminish over time due to losses in prestressing forces in the tendons and in the surrounding concrete. The prestressing force review and evaluation has been completed and determined to remain valid to the end of the subsequent period of extended operation, and the trend lines of the measured prestressing forces will stay above the minimum required prestressing forces for each group of tendons to the end of this period.	Completed
4.5	Concrete containment tendon prestress	The prestressing tendons are used to impart compressive forces in the prestressed concrete containments to resist the internal pressure inside the containment that would be generated in the event of a LOCA. The prestressing forces generated by	Completed

Table X-02 FSAR Supplement Summaries for GALL-SLR Report Aging Management Programs Discussed in SRP-SLR Chapter 4

SRP-SLR Section	TLAA	Description of Evaluation	Implementation Schedule*
		the tendons diminish over time due to losses in prestressing forces in the tendons and in the surrounding concrete. The prestressing force analysis and evaluation has been completed and determined to remain within allowable limits to the end of the subsequent period of extended operation, and the trend lines of the measured prestressing forces will stay above the minimum required prestressing forces for each group of tendons to the end of this period.	
4.5	Concrete containment tendon prestress	The prestressing tendons are used to impart compressive forces in the prestressed concrete containments to resist the internal pressure inside the containment that would be generated in the event of a LOCA. The prestressing forces generated by the tendons diminish over time due to losses of prestressing forces in the tendons and in the surrounding concrete. The [identify the aging management program] developed to monitor the prestressing forces will ensure that, during each inspection, the trend lines of the measured prestressing forces show that they meet the requirements of the ASME Code, Section XI, Subsection IWL, as incorporated by reference in 10 CFR 50.55a and supplemented. If the trend lines cross the PLLs, corrective actions should be taken. The program incorporates plant-specific and industry operating experience.	Program should be implemented before the subsequent period of extended operation.
4.6	Containment liner plates, metal containments, and penetrations fatigue	The containment liner plates, metal containments, and penetrations provide an essentially leak-tight barrier. Current fatigue parameter evaluations remain valid during the subsequent period of extended operation.	Completed
4.6	Containment liner plates, metal containments, and penetrations fatigue	The containment liner plates, metal containments, and penetrations provide an essentially leak-tight barrier. Fatigue parameter evaluations have been reevaluated based on revised numbers of occurrences and severities of cyclic loads projected for the subsequent period of extended operation. The revised fatigue parameter values remain within allowable limits for the subsequent period of extended operation.	Completed
4.6	Containment liner plates, metal containments, and penetrations fatigue	The containment liner plates, metal containments, and penetrations provide an essentially leak-tight barrier. The applicant identifies an aging management program to manage the effects of fatigue on such components during the subsequent period of extended operation. The program monitors and tracks the number of cycles and occurrences and severity of relevant transients. The program is effective when fatigue evaluations and/or fatigue usage remain within the allowable limits or requires corrective actions (e.g., re-analyses and/or component replacement) when the limits are exceeded. If the component is replaced, the	Proposed TLAA AMP should be implemented before the subsequent period of extended operation.

Table X-02 FSAR Supplement Summaries for GALL-SLR Report Aging Management Programs Discussed in SRP-SLR Chapter 4

SRP-SLR Section	TLAA	Description of Evaluation	Implementation Schedule*
		fatigue parameter value CUF for the replacement should be shown to be less than the allowable limit during the subsequent period of extended operation.	

*An applicant need not incorporate the implementation schedule into its FSAR. However, the reviewer should verify that the applicant has identified and committed in the subsequent license renewal application to any future aging management activities to be completed before the period of extended operation. The staff expects to impose a license condition on any renewed license to ensure that the applicant will complete these activities by no later than the committed date.

CHAPTER XI

AGING MANAGEMENT PROGRAMS

XI: AGING MANAGEMENT PROGRAMS

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

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	BWR FEEDWATER NOZZLE
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 (CASS)
XI.M16A	DELETED
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: AGING MANAGEMENT PROGRAMS (continued)

XI.M25	BWR REACTOR WATER CLEANUP SYSTEM
XI.M26	FIRE PROTECTION
XI.M27	FIRE WATER SYSTEM
XI.M29	ABOVEGROUND METALLIC 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.S1	ASME SECTION XI, SUBSECTION IWE
XI.S2	ASME SECTION XI, SUBSECTION IWL
XI.S3	ASME SECTION XI, SUBSECTION IWF
XI.S4	10 CFR 50, APPENDIX J
XI.S5	MASONRY WALLS
XI.S6	STRUCTURES MONITORING
XI.S7	INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

XI: AGING MANAGEMENT PROGRAMS (continued)

XI.S8	PROTECTIVE COATING MONITORING AND MAINTENANCE
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
TABLE XI-01	FSAR SUPPLEMENT SUMMARIES FOR GALL-SLR CHAPTER XI GALL-AGING MANAGEMENT PROGRAMS

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 (AMPs) in the Generic Aging Lessons Learned for Subsequent License Renewal (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 (ASME) Code], standards, and other industry-generated guidance documents. Subsequent license renewal applicants 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 a NRC Regulatory Guide (RG) endorsement, a safety evaluation for generic use [such as for a Boiling Water Reactor Vessel and Internals Project (BWRVIP)], incorporation into 10 CFR, or license renewal interim staff guidance (ISG).

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

If either of these methods is used as justification for adopting a later edition/revision than specified in the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report, the applicant shall make available for the staff's review the information pertaining to the NRC endorsement/approval of the later edition/revision.

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, imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) boiler and pressure vessel (B&PV) Code, Section XI, Rules for ISI of Nuclear Power Plant Components for Class 1, 2, and 3 pressure-retaining components and their integral attachments in light-water cooled power plants. The rules of Section XI require a mandatory program of examinations, testing and inspections to demonstrate adequate safety and to manage deterioration and aging effects. Inspection of these components is covered in Subsections IWB, IWC, and IWD, respectively, in the 2007 edition, with 2008 addenda.[1] The program generally includes periodic visual, surface, and/or volumetric examination and leakage test 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 Section XI ISI program, in accordance with Subsections IWA, IWB, IWC, and IWD, has been shown to be generally effective in managing aging effects in Class 1, 2, and 3 components and their integral attachments in light-water cooled power plants. 10 CFR 50.55a imposes additional conditions and augmentations of ISI requirements specified in 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 ISI program is augmented to manage 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 Section XI program provides the requirements for ISI, repair, and replacement of Class 1, 2, and 3 pressure-retaining components and their integral attachments in light-water cooled nuclear power plants (NPP). 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 not exempt from 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 Section XI ISI program detects degradation of components by using the examination and inspection requirements specified in ASME Section XI Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 for Class 1, 2, and 3 components, respectively.

[1]Refer to the GALL Report, Chapter I, for applicability of other editions of the ASME Code, Section XI.

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 (a) determines the general mechanical and structural condition of components and their supports by verifying parameters such as clearances, settings, and physical displacements; (b) detects discontinuities and imperfections, such as loss of integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion; and (c) observes conditions that could affect 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 ensure that aging effects are discovered and repaired 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).

   Components are examined and tested as specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 for Class 1, 2, and 3 components, 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, provides 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, and 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 and 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, and 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

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

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

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

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

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

   Boiling Water Reactor (BWR): Cracking due to intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic SSs 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) Bulletin 80-13, NRC Information Notice (IN) 95-17, NRC Generic Letter (GL) 94-03, and NUREG–1544). Cracking due to thermal and mechanical loading has occurred in high-pressure coolant injection piping (NRC IN 89-80) and instrument lines [Licensee Event Report (LER) 50-249/99-003-01]. Jet pump BWRs are designed with access holes in the shroud support plate at the bottom of the annulus between the core shroud and the reactor vessel wall. These holes are used for access during construction and are subsequently closed by welding a plate over the hole. Both circumferential (NRC IN 88-03) and radial cracking (NRC IN 92-57) have been observed in access hole covers. Failure of the isolation condenser tube bundles due to thermal fatigue and transgranular stress corrosion cracking (TGSCC) caused by leaky valves has also occurred (NRC LER 50-219/98-014-00).

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

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

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, The ASME Boiler and Pressure Vessel Code.” New York, New York: The American Society of Mechanical Engineers. 2013.[2]

EPRI. BWRVIP-03, “BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines (EPRI TR-105696 R1, March 30, 1999).” July 1999.

Licensee Event Report LER 50-249/99-003-01, “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.” https://lersearch.inl.gov/LERSearchCriteria.aspx. August 1999.

Licensee Event Report LER 50-219/98-014-00, “Failure of the Isolation Condenser Tube Bundles due to Thermal Stresses/Transgranular Stress Corrosion Cracking Caused by Leaky Valve.” https://lersearch.inl.gov/LERSearchCriteria.aspx. October 1998.

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

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

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

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

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

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

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

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

_____. NRC 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.

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

_____. Generic Letter 94-03, “Intergranular Stress Corrosion Cracking of Core Shrouds in Boiling Water Reactors. ML070600206. Washington DC: U.S. Nuclear Regulatory Commission. July 1994.

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

_____. NRC 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 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 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.

_____. “Thermal Stresses in Piping Connected to Reactor Coolant System.” Bulletin 88-08. Washington DC: U.S. Nuclear Regulatory Commission. June 1988. Supplement 1, June 1988. Supplement 2, September 1988. Supplement 3, April1989.

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

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

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

_____. NRC Information Notice 82-37, “Cracking in the Upper Shell to Transition Cone Girth Weld of a Steam Generator at an Operating PWR.” ML082970942. Washington, DC: U.S. Nuclear Regulatory Commission. September 1982.

_____. Bulletin 80-13, “Cracking in Core Spray Spargers.” Accession No. 8002280661. Washington, DC: U.S. Nuclear Regulatory Commission. May 1980.

_____. NRC Information Notice 80-38, “Cracking in Charging Pump Casing Cladding.” ML073550834. Washington, DC: U.S. Nuclear Regulatory Commission. October 1980.

XI.M2 WATER CHEMISTRY

Program Description

The main objective of this program is to mitigate loss of material due to corrosion, cracking due to stress corrosion cracking (SCC) and related mechanisms, and reduction of heat transfer due to fouling in components exposed to a treated water environment. The program includes periodic monitoring of the treated water in order to minimize loss of material or cracking.

The water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines contained in the Boiling Water Reactor Vessel and Internals Project (BWRVIP)-190 [Electric Power Research Institute (EPRI) 1016579]. The BWRVIP-190 has three sets of guidelines: (i) one for reactor water, (ii) one for condensate and feedwater, and (iii) one for control rod drive (CRD) 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 1014986, “PWR Primary Water Chemistry Guidelines,” Revision 6 and EPRI 1016555, “PWR Secondary Water Chemistry Guidelines,” Revision 7.

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

Evaluation and Technical Basis

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

2. ***Preventive Actions**:* The program includes specifications for chemical species, impurities and additives, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to general, crevice, and pitting corrosion and cracking caused by SCC. For BWRs, maintaining high water purity reduces susceptibility to SCC, and chemical additive programs such as hydrogen water chemistry or noble metal chemical application also may be used. For PWRs, additives are used for reactivity control and to control pH 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 ensure 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 is performed in accordance with the EPRI water chemistry guidelines and based on plant operating conditions. The main objective of this program is to mitigate 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   Any evidence of aging effects or unacceptable water chemistry results are 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 those specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

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

BWR: Intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic stainless steels (SSs) and nickel-base 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 core shroud, access hole cover, top guide, and core spray spargers [NRC Bulletin 80-13, NRC Information Notice (IN) 95-17, NRC Generic Letter (GL) 94-03, and NUREG–1544]. No occurrence of SCC in piping and other components in standby liquid control systems exposed to sodium pentaborate solution has ever been reported (NUREG/CR–6001).

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

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

Such operating experience has provided feedback to revisions of the Electric Power Research Institute (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 operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. EPRI 1016555, "PWR Secondary Water Chemistry Guidelines–Revision 7." Palo Alto, California: Electric Power Research Institute. February 2009.

_____. BWRVIP-190 (EPRI 1016579), "BWR Vessel and Internals Project: BWR Water Chemistry Guidelines-2008 Revision." Palo Alto, California: Electric Power Research Institute. October 2008.

_____. EPRI 1014986, "PWR Primary Water Chemistry Guidelines." Revision 6, Volumes 1 and 2, Palo Alto, California: Electric Power Research Institute. December 2007.

NRC. NRC Information Notice 2007-37, "Buildup of Deposits in Steam Generators." Washington, DC: U.S. Nuclear Regulatory Commission. November 2007.

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

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

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

_____. 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 Information Notice 95-17, "Reactor Vessel Top Guide and Core Plate Cracking." U.S. Nuclear Regulatory Commission. March 1995.

_____. NRC Generic Letter 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking." Washington, DC: U.S. Nuclear Regulatory Commission. August 1995.

_____. NRC Information Notice 94-87, "Unanticipated Crack in a Particular Heat of Alloy 600 Used for Westinghouse Mechanical Plugs for Steam Generator Tubes." U.S. Nuclear Regulatory Commission. December 1994.

_____. NRC 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 Generic Letter 94-03, “Intergranular Stress Corrosion Cracking of Core Shrouds in Boiling Water Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1994.

_____. NUREG/CR-6001, “Aging Assessment of BWR Standby Liquid Control Systems.” G.D. Buckley, R.D. Orton, A.B. Johnson Jr., and L.L. Larson. Washington, DC: U.S. Nuclear Regulatory Commission. 1992.

_____. NRC 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 Bulletin 89-01, Supplement 2, “Failure of Westinghouse Steam Generator Tube Mechanical Plugs.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1991.

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

_____. NRC 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 Information Notice 89-33, “Potential Failure of Westinghouse Steam Generator Tube Mechanical Plugs.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1989.

_____. NRC Bulletin 89-01, “Failure of Westinghouse Steam Generator Tube Mechanical Plugs.” Washington, DC: U.S. Nuclear Regulatory Commission. May 1989.

_____. NRC Bulletin 89-01, “Supplement 1, “Failure of Westinghouse Steam Generator Tube Mechanical Plugs.” Washington, DC: U.S. Nuclear Regulatory Commission. November 1989.

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

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

_____. NRC Information Notice 82-37, “Cracking in the Upper Shell to Transition Cone Girth Weld of a Steam Generator at an Operating PWR.” Washington, DC: U.S. Nuclear Regulatory Commission. September 1982.

_____. NRC Information Notice 80-38, “Cracking In Charging Pump Casing Cladding.” Washington, DC: U.S. Nuclear Regulatory Commission. October 1980.

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

XI.M3 REACTOR HEAD CLOSURE STUD BOLTING

Program Description

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

Evaluation and Technical Basis

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

2. ***Preventive Actions**:* Preventive measures may include:

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

   (b) Using manganese phosphate or other acceptable surface treatments;

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

   (d) Using bolting material for closure studs that has an actual measured yield strength less than 1,034 megapascals (MPa) (150 kilo-pounds per square inch).

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

3. ***Parameters Monitored or Inspected**:* The ASME 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 and ensure that aging effects are discovered and repaired before the loss of intended function of the component. Inspection can reveal cracking, loss of material due to corrosion or wear, and leakage of coolant.

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

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 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management programs (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   Repair and replacement are performed in accordance with the requirements of IWA-4000 and the material and inspection guidance of Regulatory Guide (RG) 1.65. The maximum yield strength of replacement material should be limited as recommended in RG 1.65

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

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

10. ***Operating Experience****:* SCC has occurred in BWR pressure vessel head studs (Stoller, 1991). The AMP has provisions regarding inspection techniques and evaluation, material specifications, corrosion prevention, and other aspects of reactor

pressure vessel (RPV) 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 (CLB) for the period of extended operation. Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, SCC, and fatigue loading (NRC Inspection and Enforcement Bulletin 82-02, NRC Generic Letter 91-17).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” The ASME Boiler and Pressure Vessel Code. New York, New York. The American Society of Mechanical Engineers. 2013.[1]

NRC. NRC Regulatory Guide 1.65, “Material and Inspection for Reactor Vessel Closure Studs.” Revision 1. Washington, DC: U.S. Nuclear Regulatory Commission. April 2010.

_____. NRC Generic Letter 91-17, “Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. October 1991.

_____. NRC Inspection and Enforcement Bulletin 82-02, “Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1982.

Stoller, S.M. “Reactor Head Closure Stud Cracking, Material Toughness Outside FSAR–SCC in Thread Roots.” BWR-2, III, 58. *Nuclear Power Experience*. 1991.

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

XI.M4 BOILING WATER REACTOR 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 (ASME) Code, Section XI, and the guidance in "BWR Vessel and Internals Project, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines" (BWRVIP-48-A) to provide reasonable assurance of the long-term integrity and safe operation of BWR vessel ID attachment welds.

The guidance in Boiling Water Reactor Vessel and Internals Project (BWRVIP)-48-A includes inspection recommendations and evaluation methodologies for certain attachment welds between the vessel wall and the brackets that attach components to the vessel. In some cases, the attachment is a weld attached directly to the vessel wall; in other cases, the attachment includes a weld build-up pad on the vessel wall. The BWRVIP-48-A report includes information on 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 structural integrity significance of 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 those BWR vessel ID attachment welds that are covered by BWRVIP-48-A. The program is an augmented inservice inspection (ISI) program that uses the inspection and flaw evaluation criteria in BWRVIP-48-A to detect cracking and monitor the effects of cracking on the intended functions of these components.

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

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

4. ***Detection of Aging Effects****:* The extent and schedule of the inspections prescribed by BWRVIP-48-A and ASME Code, Section XI, are designed to maintain structural integrity and ensure that aging effects are discovered and repaired 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. In addition, certain attachment welds are subject to augmented examinations. BWRVIP-48-A specifies the nondestructive examination methods, inspection locations,

and inspection frequencies for these augmented examinations. The nondestructive examination techniques that are appropriate for the augmented examinations, including the uncertainties inherent in delivering and executing these techniques and applicable for inclusion in flaw evaluations, are included in BWRVIP-03.

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

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

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

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

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

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

10. ***Operating Experience****:* Cracking due to SCC, IGSCC, and cyclical loading has occurred in BWR components. The program guidelines are based on an evaluation of available information, including BWR inspection data and information on the causes of SCC, IGSCC, and cracking due to cyclical loading, to determine which attachment welds may be susceptible to cracking from 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 (CLB) 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.[1]

EPRI. BWRVIP-03, Revision 16 (EPRI 105696-R16), “BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines.” Palo Alto, California: Electric Power Research Institute. December 2013.

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

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

_____. BWRVIP-52-A (EPRI 1012119), *“BWR Vessel and Internals Project, Shroud Support and Vessel Bracket Repair Design Criteria.” Palo Alto, California: Electric Power Research Institute.* September 2005.

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

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

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

XI.M5 BOILING WATER REACTOR FEEDWATER NOZZLE

Program Description

This program is a condition monitoring program for detecting cracking due to fatigue in boiling water reactor (BWR) feedwater nozzles. Cracking is detected through qualified ultrasonic examinations, the extent and frequency of which are based on the recommendations in General Electric Report GE-NE-523-A71-0594-A, Revision 1, “Alternate BWR Feedwater Nozzle Inspection Requirements.” These examinations augment the inservice inspection (ISIs) specified by Section XI of the American Society of Mechanical Engineers (ASME) Code.

Evaluation and Technical Basis

1. ***Scope of Program****:* This program manages the effects of cracking due to fatigue of the BWR feedwater nozzles.

2. ***Preventive Actions****:* This is a condition monitoring program only; therefore, it has no preventive actions.

3. ***Parameters Monitored or Inspected****:* The volume of certain critical regions of the BWR feedwater nozzle is examined to detect flaws or other discontinuities that may indicate the presence of cracks.

4. ***Detection of Aging Effects****:* Cracking is detected through ultrasonic examinations of critical regions of the BWR feedwater nozzle. These critical regions cover the feedwater nozzle inner radius and bore as depicted in Zones 1, 2, and 3 on Figures 4-1 and 4-2 of GE-NE-523-A71-0594-A, Revision 1. The ultrasonic examination procedures, equipment, and personnel are qualified by performance demonstration in accordance with ASME Code, Section XI, Appendix VIII.

   For plants without single sleeve interference fit feedwater spargers, the examination frequency for Zones 1, 2, and 3 is once every 10-year ASME Code, Section XI, ISI interval.

   For plants with single sleeve interference fit feedwater spargers, the inspection interval for Zones 1 and 2 is in accordance with Table 6-1 of GE-NE-523-A71-0594-A, Revision 1. This inspection interval is based on the results of a plant-specific fracture mechanics analysis and the particular type of ultrasonic examination method that is employed. The plant-specific fracture mechanics analysis should use the latest ASME fatigue crack growth rates in a water environment that have been endorsed by the U.S. Nuclear Regulatory Commission (NRC). For these plants, the inspection interval for Zone 3 is twice the inspection interval established for Zones 1 and 2, not to exceed once every 10 years.

5. ***Monitoring and Trending****:* Augmented examinations in accordance with GE-NE-523-A71-0594-A, Revision 1 provide for the timely detection of cracks. For plants with single sleeve interference fit feedwater spargers, the cycles assumed in the plant-specific fracture mechanics analysis are monitored in accordance with activities that meet the guidelines in GALL-SLR Report AMP X.M1, “Cyclic Load Monitoring.” This monitoring is used to assess the continued validity of the fracture mechanics analysis.

6. ***Acceptance Criteria****:* Examination results are evaluated in accordance with ASME Code, Section XI, Subsubsection IWB-3130.

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

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

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

10. ***Operating Experience****:* NUREG–0619, *BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking*, summarizes cracking that occurred in the feedwater nozzles of several BWRs in the late 1970’s. In response to NUREG–0619, licensees implemented various hardware modifications and changes to operating procedures to decrease the magnitude and frequency of temperature fluctuations that had led to the cracking. This AMP augments the ASME Code, Section XI, inspections to provide assurance that any further cracking in BWR feedwater nozzles will be detected before there is a loss of intended function.

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

GE. GE-NE-523-A71-0594-A, “Alternate BWR Feedwater Nozzle Inspection Requirements.” Revision 1. ML003723265. General Electric, May 2000.

NRC. NRC Generic Letter 81-11, “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking (NUREG–0619).” Washington, DC: U.S. Nuclear Regulatory Commission. February 1981.

[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.

XI.M6 DELETED

XI.M7 BOILING WATER REACTOR STRESS CORROSION CRACKING

Program Description

The program to manage intergranular stress corrosion cracking (IGSCC) in boiling water reactor (BWR) coolant pressure boundary piping made of stainless steel (SS) and nickel-based alloy components is delineated in NUREG–0313, Revision 2, and the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-01 and its Supplement 1. The material includes base metal and welds. The comprehensive program outlined in NUREG–0313, Revision 2 and NRC GL 88-01 describes improvements that, in combination, will reduce the susceptibility to IGSCC. The elements to 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 SCC. Residual tensile stresses are introduced from 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 stress corrosion cracking (SCC) processes. The program includes (a) preventive measures to mitigate IGSCC and (b) inspection and flaw evaluation to monitor IGSCC and its effects. The staff-approved Boiling Water Reactor Vessel and Internals Project (BWRVIP) (BWRVIP-75-A) report allows for modifications to the inspection extent and schedule described in the GL 88-01 program.

Evaluation and Technical Basis

1. ***Scope of Program**:* The program focuses on (a) managing and implementing countermeasures to mitigate IGSCC and (b) 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 60 °C [140 °F] 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 are included in the scope of the program. NUREG–0313, Rev. 2 and NRC GL 88-01, respectively, describe the technical basis and staff guidance regarding mitigation of IGSCC in BWRs. Attachment A of NRC GL 88-01 delineates the staff-approved positions regarding materials, processes, water chemistry, weld overlay reinforcement, partial replacement, stress improvement of cracked welds, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting requirements.

2. ***Preventive Actions**:* The BWR SCC program is primarily a condition monitoring program which 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, Rev. 2 and GL 88-01 delineate the guidance for selection of resistant materials and processes that provide

resistance to IGSCC such as solution heat treatment and stress improvement processes.

3. ***Parameters Monitored or Inspected****:* The program detects and sizes cracks and detects leakage by using the examination and inspection guidelines delineated in NUREG–0313, Rev. 2, and NRC GL 88-01 or the referenced BWRVIP-75-A guideline as approved by the NRC staff.

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

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

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

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

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

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

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

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

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

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, "Codes and Standards." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." ASME Boiler and Pressure Vessel Code, New York, New York: The American Society of Mechanical Engineers. 2013.[1]

_____. ASME Code Case N-504-4, "Alternative Rules for Repair of Class 1, 2, and 3 Austenitic Stainless Steel Piping." Section XI, Division 1. New York, New York: American Society of Mechanical Engineers. July 2006.

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

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

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

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

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

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

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

_____. 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.

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

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

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

XI.M8 BOILING WATER REACTOR PENETRATIONS

Program Description

The program for boiling water reactor (BWR) vessel instrumentation penetrations, control rod drive (CRD) housing and incore-monitoring housing (ICMH) penetrations and standby liquid control (SLC) nozzles/Core ΔP nozzles includes inspection and flaw evaluation in conformance with the guidelines of staff-approved Boiling Water Reactor Vessel and Internals Project (BWRVIP) Topical Reports BWRVIP-49-A, BWRVIP-47-A and BWRVIP-27-A. The program manages cracking due to cyclic loading, stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) for these BWR vessel penetrations and nozzles. The inspection and evaluation guidelines of BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A contain generic guidelines intended to present appropriate inspection recommendations to assure safety function integrity. The guidelines of BWRVIP-49-A provide information on 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 on components located in the lower plenum region of BWRs, evaluate their susceptibility and consequences of failure, and define the inspection strategy to assure safe operation. The guidelines of BWRVIP-27-A are applicable to plants in which the SLC system injects sodium pentaborate into the bottom head region of the vessel (in most plants, as a pipe within a pipe of the core plate ΔP monitoring system). The BWRVIP-27-A guidelines address the region where the ΔP and SLC nozzle or housing penetrates the vessel bottom head and include the safe ends welded to the nozzle or housing. Guidelines for repair design criteria are provided in BWRVIP-57-A for instrumentation penetrations, BWRVIP-55-A for CRD housing and ICMH penetrations and BWRVIP-53-A for 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 BWRVIP-190 (EPRI 1016579) or later revisions. BWRVIP-190 has three sets of guidelines: (i) one for primary water, (ii) one for condensate and feedwater, and (iii) one for CRD mechanism cooling water. Adequate aging management activities for these components provide reasonable assurance that the long-term integrity and safe operation of BWR vessel instrumentation nozzles, CRD housing and ICMH penetrations and SLC nozzles/Core ΔP nozzles.

Evaluation and Technical Basis

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

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

3. ***Parameters Monitored or Inspected***: The program manages the effects of cracking due to SCC/IGSCC on the intended function of the BWR instrumentation nozzles, CRD housing and ICMH penetrations, and BWR SLC nozzles/Core ΔP nozzles. The program monitors for evidence of surface-breaking linear discontinuities if a visual inspection technique is used or for relevant flaw signals if a volumetric ultrasonic testing (UT) method is used. In addition, the program includes visual examination to confirm the absence of leakage.

4. ***Detection of Aging Effects***: The inspection guidelines of BWRVIP-49-A, BWRVIP-47-A and BWRVIP-27-A, along with the existing inspection requirements in American Society of Mechanical Engineers (ASME) Code, Section XI, Table IWB-2500-1, are sufficient to monitor for indications of cracking in BWR instrumentation nozzles, CRD housing and ICMH penetrations and BWR SLC nozzles/Core ΔP nozzles, and should continue to be followed for the subsequent period of extended operation. The extent and schedule of 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 and ensure that aging effects are discovered and repaired 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 (RT)], surface examination methods (liquid penetrant testing or magnetic particle testing), and VT-2 visual examination methods.

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

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

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

   Corrective actions include repair and replacement procedures in staff-approved BWRVIP-57-A, BWRVIP-55-A, BWRVIP-58-A and BWRVIP-53-A that are equivalent to those required in ASME Code, Section XI. Guidelines for repair design criteria are provided in BWRVIP-57-A for instrumentation penetrations, BWRVIP-55-A for CRD housing and ICMH penetrations, and 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 those specific portions of the QA program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

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

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

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” The ASME Boiler and Pressure Vessel Code, New York, New York: The American Society of Mechanical Engineers. 2013.[1]

EPRI. BWRVIP-190 (EPRI 1016579), “BWR Vessel and Internals Project, BWR Water Chemistry Guidelines-2008 Revision.” Palo Alto, California: Electric Power Research Institute. October 2008.

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

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

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

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

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

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

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

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

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

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

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

XI.M9 BOILING WATER REACTOR VESSEL INTERNALS

Program Description

The 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 on 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 wt. 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 wt. 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 in determining susceptibility of CASS to neutron and thermal embrittlement.

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 [482°F]. 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, 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. 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**:* The 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. This program also includes 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, 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 as subject to the following staff-approved applicable BWRVIP guidelines:

   Core shroud: BWRVIP-76-A provides guidelines for inspection and evaluation; BWRVIP-02-A, Revision 2, provides guidelines for repair design criteria.

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

   Core spray: BWRVIP-18, Revision 1-A provides guidelines for inspection and evaluation; BWRVIP-16-A and BWRVIP-19-A provide guidelines for replacement and repair design criteria, respectively.

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

   Jet pump assembly: BWRVIP-41 provides guidelines for inspection and evaluation; BWRVIP-51-A provides guidelines for repair design criteria.

   Low-pressure coolant injection (LPCI) coupling: BWRVIP-42-A provides guidelines for inspection and evaluation; BWRVIP-56-A provides guidelines for repair design criteria.

   Top guide: BWRVIP-26-A and BWRVIP-183 provide guidelines for inspection and evaluation; BWRVIP-50-A provides guidelines for repair design criteria. The program inspects 5 percent of the top guide locations using enhanced visual inspection technique, EVT-1 within 6 years after entering the subsequent period of extended operation. An additional 5 percent of the top guide locations will be inspected within 12 years after entering the subsequent period of extended operation.

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 (HAZ) 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. 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 (CRD) housing and lower plenum components: BWRVIP-47-A provides guidelines for inspection and evaluation; BWRVIP-55-A provides guidelines for repair design criteria.

Steam dryer: BWRVIP-139-A provides guidelines for inspection and evaluation for the steam dryer components; BWRVIP-181-A provides guidelines for repair design criteria.

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****:* The 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 (ASME) Code, Section XI, Table IWB 2500-1.

Loss of fracture toughness due to neutron embrittlement in CASS materials can occur with a neutron fluence greater than 1×10^{17} n/cm^2 [E>1 MeV]. Loss 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, U.S. Nuclear Regulatory Commission (NRC), to Mr. Douglas Walters, Nuclear Energy Institute (NEI). A subsequent license renewal applicant may use alternative staff-approved screening criteria in determining susceptibility of CASS to neutron and thermal embrittlement. 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 inservice inspection (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 holddown bolts and jet pump assembly holddown beam bolts by performing visual inspections or stress analyses to ensure adequate structural integrity.

4. ***Detection of Aging Effects**:* The extent and schedule of the inspection and test techniques prescribed by the applicable and staff-approved BWRVIP guidelines are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function of BWR vessel internals. Vessel internal components are inspected in accordance with the requirements of ASME Section XI, Subsection IWB, Examination Category B-N-2. The ASME Section XI inspection specifies visual VT-1 examination to detect discontinuities and imperfections, such as cracks, corrosion, wear, or erosion, on the surfaces of components. This inspection also specifies visual VT-3 examination to determine the general mechanical and structural condition of the component supports by (a) verifying parameters, such as clearances, settings, and physical displacements and (b) 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 (UT)].

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.

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 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 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 are 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 towards trending. The BWRVIP guidelines provide recommendations for expanding the sample scope and reinspecting the components if flaws are detected. Any indication detected is evaluated in accordance with ASME Code, Section XI or the applicable BWRVIP guidelines. BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, BWRVIP-80-A and BWRVIP-99-A documents provide additional guidelines for evaluation of crack growth in SSs, nickel alloys, and low-alloy steels. BWRVIP-100-A describes flaw evaluation methodologies and fracture toughness data for SS core shroud exposed to neutron irradiation.

   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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   Repair and replacement procedures are equivalent to those 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. 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 those specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

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

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

Cracking of the core plate has not been reported, but the creviced regions beneath the plate are difficult to inspect. BWRVIP-06R1-A and BWRVIP-25 address the safety significance and inspection requirements for the core plate assembly. Only inspection of core plate bolts (for plants without retaining wedges) or inspection of the retaining wedges is required. NRC IN 95-17 discusses cracking in top guides of United States and overseas BWRs. Related experience in other components is reviewed in NRC GL 94-03 and NUREG–1544. Cracking has also been observed in the top guide of a Swedish BWR.

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

Two control rod drive mechanism (CRDM) lead screw male couplings were fractured in a pressurized water reactor (PWR), designed by Babcock & Wilcox (B&W), at Oconee Nuclear Station (ONS), Unit 3. The fracture was due to thermal embrittlement of 17-4 precipitation-hardened (PH) material (NRC IN 2007-02). While this occurred at a PWR, it also needs to be considered for 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 on 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 (CLB) for the 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.[1]

EPRI. EPRI 3002000628, “Materials Degradation Matrix.” Revision 1. Palo Alto, California: Electric Power Research Institute. May 2013.

_____. BWRVIP-167NP (EPRI 3002000690) “BWR Vessel and Internals Project Boiling Water Reactor Issue Management Tables.” Revision 1. Palo Alto, California: Electric Power Research Institute. August 2013.

_____. BWRVIP-84 (EPRI 1026603), “BWR Vessel and Internals Project, Guidelines for Selection and Use of Materials for Repairs to BWR Internal Components.” Revision 2. Palo Alto, California: Electric Power Research Institute. September 2012.

_____. BWRVIP-18-A, Revision 1 (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.

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

_____. BWRVIP-181-A (EPRI 1020997), "BWR Vessel and Internals Project, Steam Dryer Repair Design Criteria." Palo Alto, California: Electric Power Research Institute. July 2010.

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

_____. BWRVIP-139-A (EPRI 1018794), "BWR Vessel and Internals Project, Steam Dryer Inspection and Flaw Evaluation Guidelines." Palo Alto, California: Electric Power Research Institute. July 2009.

_____. BWRVIP-97-A (EPRI 1019054), "BWR Vessel and Internals Project, Guidelines for Performing Weld Repairs to Irradiated BWR Internals." Palo Alto, California: Electric Power Research Institute. June 2009.

_____. BWRVIP-76-A (EPRI 1019057), "BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines." Palo Alto, California: Electric Power Research Institute. October 2009.

_____. BWRVIP-06R1-A (EPRI 1019058), "Safety Assessment of BWR Reactor Internals." Palo Alto, California: Electric Power Research Institute. December 2009.

_____. BWRVIP-190 (EPRI 1016579), "BWR Vessel and Internals Project: BWR Water Chemistry Guidelines—2008 Revision." Palo Alto, California: Electric Power Research Institute. October 2008.

_____. BWRVIP-99-A (EPRI 1016566), "BWR Vessel and Internals Project, Crack Growth Rates in Irradiated Stainless Steels in BWR Internal Components." Palo Alto, California: Electric Power Research Institute. October 2008.

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

_____. BWRVIP-183 (EPRI 1013401), "BWR Vessel and Internals Project, Top Guide Beam Inspection and Flaw Evaluation Guidelines." Palo Alto, California: Electric Power Research Institute. December 2007.

_____. BWRVIP-80-A (EPRI 1015457), "BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Shroud Vertical Welds." Palo Alto, California: Electric Power Research Institute. October 2007.

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

_____. BWRVIP-100-A (EPRI 1013396), "BWR Vessel and Internals Project, Updated Assessment of the Fracture Toughness of Irradiated Stainless Steel for BWR Core Shrouds." Palo Alto, California: Electric Power Research Institute. August 2006.

_____. BWRVIP-44-A (EPRI 1014352), “BWR Vessel and Internals Project, Underwater Weld Repair of Nickel Alloy Reactor Vessel Internals.” Palo Alto, California: Electric Power Research Institute. August 2006.

_____. BWRVIP-56-A (EPRI 1012118), “BWR Vessel and Internals Project, LPCI Coupling Repair Design Criteria.” Palo Alto, California: Electric Power Research Institute. September 2005.

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

_____. BWRVIP-52-A (EPRI 1012119), “BWR Vessel and Internals Project, Shroud Support and Vessel Bracket Repair Design Criteria.” Palo Alto, California: Electric Power Research Institute. September 2005.

_____. BWRVIP-51-A (EPRI 1012116), “BWR Vessel and Internals Project, Jet Pump Repair Design Criteria.” Palo Alto, California: Electric Power Research Institute. September 2005.

_____. BWRVIP-50-A (EPRI 1012110), “BWR Vessel and Internals Project, Top Guide/Core Plate Repair Design Criteria.” Palo Alto, California: Electric Power Research Institute. September 2005.

_____. BWRVIP-42-A (EPRI 1011470), “BWR Vessel and Internals Project, BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines.” Palo Alto, California: Electric Power Research Institute. February 2005.

_____. BWRVIP-19-A (EPRI 1012114), “BWR Vessel and Internals Project, Internal Core Spray Piping and Sparger Repair Design Criteria.” Palo Alto, California: Electric Power Research Institute. September 2005.

_____. BWRVIP-16-A (EPRI 1012113), “BWR Vessel and Internals Project, Internal Core Spray Piping and Sparger Replacement Design Criteria.” Palo Alto, California: Electric Power Research Institute. September 2005.

_____. BWRVIP-02-A, Revision 2 (EPRI 1012837), “BWR Vessel and Internals Project, BWR Core Shroud Repair Design Criteria.” Palo Alto, California: Electric Power Research Institute. October 2005.

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

_____. BWRVIP-26-A (EPRI 1009946), “BWR Vessel and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines.” Palo Alto, California: Electric Power Research Institute. November 2004.

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

_____. BWRVIP-45 (EPRI 108707), "BWR Vessel and Internals Project, Weldability of Irradiated LWR Structural Components." Palo Alto, California: Electric Power Research Institute. June 2000.

_____. BWRVIP-25 (EPRI 107284), "BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines." Palo Alto, California: Electric Power Research Institute. December 2000.

_____. BWRVIP-03 (EPRI 105696 R1, March 30, 1999), "BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines." Palo Alto, California: Electric Power Research Institute. July 1999.

_____. BWRVIP-38 (EPRI 108823), "BWR Vessel and Internals Project, BWR Shroud Support Inspection and Flaw Evaluation Guidelines." Palo Alto, California: Electric Power Research Institute. September 1997.

_____. BWRVIP-41 (EPRI 108728), "BWR Vessel and Internals Project, BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines." Palo Alto, California: Electric Power Research Institute. October 1997.

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 Vessels and Piping*. pp. 37–44. 1997.

NRC. NUREG/CR–6923, "Expert Panel Report on Proactive Materials Degradation Assessment." Washington, DC: U.S. Nuclear Regulatory Commission. March 2007.

_____. NRC Information Notice 2007-02, "Failure of Control Rod Drive Mechanism Lead Screw Male Coupling at Babcock and Wilcox-Designed Facility." Washington, DC: U.S. Nuclear Regulatory Commission. March 2007.

_____. Letter from Christopher I. Grimes, U.S. Nuclear Regulatory Commission, License Renewal and Standardization Branch, to Douglas J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Stainless Steel Components." ML003717179. May 19, 2000.

_____. NRC Information Notice 97-17, "Cracking of Vertical Welds in the Core Shroud and Degraded Repair." Washington, DC: U.S. Nuclear Regulatory Commission. April 1997.

_____. NRC Information Notice 97-02, "Cracks Found in Jet Pump Riser Assembly Elbows at Boiling Water Reactors." Washington, DC: U.S. Nuclear Regulatory Commission. February 1997.

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

_____. NUREG/CR–4513, “Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR Systems.” Revision 1. Washington, DC: U.S. Nuclear Regulatory Commission. August 1994.

_____. NRC Information Notice 94-42, “Cracking in the Lower Region of the Core Shroud in Boiling Water Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1994.

_____. NRC Generic Letter 94-03, “Intergranular Stress Corrosion Cracking of Core Shrouds in Boiling Water Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1994.

_____. NRC Information Notice 93-101, “Jet Pump Hold-Down Beam Failure.” Washington, DC: U.S. Nuclear Regulatory Commission. December 1993.

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

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

_____. NRC Bulletin No. 80-13, “Cracking in Core Spray Spargers.” Washington, DC: U.S. Nuclear Regulatory Commission. May 1980.

_____. NRC Bulletin No. 80-07, “BWR Jet Pump Assembly Failure.” Washington, DC: U.S. Nuclear Regulatory Commission. April 1980.

_____. NRC Bulletin No. 80-07, Supplement 1, “BWR Jet Pump Assembly Failure.” Washington, DC: U.S. Nuclear Regulatory Commission. May 1980.

Xu, H. and S. Fyfitch. “Fracture of Type 17-4 PH CRDM Lead Screw Male Coupling Tangs.” 11th International Conference on Environmental Degradation of Materials in Nuclear Power Systems-Water Reactors. Stevenson, Washington. American Nuclear Society. 2003.

XI.M10 BORIC ACID CORROSION

Program Description

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

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

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) aging management program (AMP) XI.M11B, “Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs only).”

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

Evaluation and Technical Basis

1. ***Scope of Program****:* The program covers any structures or components on which boric acid corrosion may occur (e.g., steel, copper alloy, and aluminum) and electrical components onto which borated reactor water may leak. The program includes provisions in response to the recommendations of NRC GL 88-05. NRC GL 88-05 elicits a program consisting of systematic measures to ensure that corrosion caused by leaking borated water does not lead to degradation of the leakage source or adjacent structures and components, 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 (a) determination of the principal location of leakage, (b) examinations and procedures for locating small leaks, and (c) engineering evaluations and corrective actions to ensure 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 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.

   In order to identify potential plant issues not 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 (CRD) 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. Discoloration, staining, boric acid residue, and other evidence of leakage on insulation surfaces and the surrounding area are given particular consideration as evidence of component leakage. The program delineated in NRC GL 88-05 includes guidelines for locating small leaks, conducting examinations, and performing engineering evaluations. In addition, the program includes appropriate interfaces with other site programs and activities, such that borated water leakage that is encountered by means other than the monitoring and trending established by this program is evaluated and corrected.

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

6. ***Acceptance Criteria***: Any detected borated water leakage, white or discolored crystal buildup, or rust-colored deposits are evaluated to confirm or restore 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 as conditions adverse to quality or significant conditions adverse to quality under those 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, quality assurance (QA) program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

Borated water leakage and areas of resulting boric acid corrosion are evaluated and corrected in accordance with the applicable provisions of NRC GL 88-05 and the corrective action program. Any detected boric acid crystal buildup or deposits should be cleaned. NRC GL 88-05 recommends that corrective actions to prevent recurrences of degradation caused by borated water leakage be included in the program implementation. These corrective actions include any modifications to be introduced in the present design or operating procedures of the plant that (a) reduce the probability of reactor coolant leaks at locations where they may cause corrosion damage and (b) 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) 201215]. Such modifications should allow for periodic inspections.

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

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

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

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

Licensee Event Report 250/2010-005, “Containment Liner Through Wall Defect Due to Corrosion.” ML103620112. https://lersearch.inl.gov/LERSearchCriteria.aspx. December 2010.

Licensee Event Report 346/2002-008, “Containment Air Coolers Collective Significance of Degraded Conditions.” ML031330192. https://lersearch.inl.gov/LERSearchCriteria.aspx. May 2003

Licensee Event Report 346/1998-009, “Reactor Coolant System Pressurizer Spray Valve Degraded with Two of Eight Body-to-Bonnet Nuts Missing.” https://lersearch.inl.gov/LERSearchCriteria.aspx. August 1999.

NRC. NRC Information Notice 2012-15, “Use of Seal Cap Enclosures to Mitigate Leakage from Joints that Use A-286 Bolts.” Washington, DC: U.S. Nuclear Regulatory Commission. August 2012.

_____. 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 Regulatory Issue Summary 2003-13, “NRC Review of Responses to Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity.” Washington, DC: U.S. Nuclear Regulatory Commission. July 2003.

_____. NRC Information Notice 2003-02, “Recent Experience with Reactor Coolant System Leakage and Boric Acid Corrosion.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2003.

_____. NRC Information Notice 2002-13, “Possible Indicators of Ongoing Reactor Pressure Vessel Head Degradation.” Washington, DC: U.S. Nuclear Regulatory Commission. April 2002.

_____. NRC Information Notice 2002-11, “Recent Experience with Degradation of Reactor Pressure Vessel Head.” Washington, DC: U.S. Nuclear Regulatory Commission. March 2002.

_____. NRC Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity.” Washington, DC: U.S. Nuclear Regulatory Commission. March 2002.

_____. NRC Information Notice 86-108, “Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion.” Washington, DC: U.S. Nuclear Regulatory Commission, December 26, 1986; Supplement 1, April 20, 1987; Supplement 2, November 19, 1987; and Supplement 3, January 1995.

_____. NRC Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1988.

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

XI.M11B CRACKING OF NICKEL-ALLOY COMPONENTS AND LOSS OF MATERIAL DUE TO BORIC ACID-INDUCED CORROSION IN REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS (PRESSURIZED WATER REACTORS ONLY)

Program Description

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 pressurized water reactor (PWR) primary coolant at elevated temperature. The initiation and growth of PWSCC cracks have been shown to be a function of several variables, including but not limited to: (i) temperature, (ii) stress, (iii) microstructure, (iv) time, and (v) 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 cracking of nickel alloy components, this program also contains inspections designed to potentially identify the presence of boric acid residues, which has been demonstrated by operating experience 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 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) 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: (i) all nickel alloy components and welds which are identified at the plant in accordance with the guidelines of Electric Power Research Institute (EPRI) Materials Reliability Program (MRP)-126; (ii) nickel alloy components and welds identified in American Society of Mechanical Engineers (ASME)[1] Code Cases N-770, N-729 and N-722, as incorporated by reference in 10 CFR 50.55a; and (iii) components that are susceptible to corrosion by boric acid and may be impacted 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. Since the cracking of nickel alloys is affected by water quality this program is used in

[1]Refer to the GALL-SLR Report, Chapter 1, for applicability of other editions of the ASME Code.

conjunction with GALL-SLR Report AMP XI.M2, "Water Chemistry." Additionally, in accordance with 10 CFR 50.55a, an applicant may choose to mitigate components in lieu of performing required inspections.

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. In the event boric acid residues or corrosion products are discovered during these inspections, the potential for, or extent of, loss of material is evaluated by visual and quantitative methods.

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

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

   In addition, this program performs a baseline inspection of bottom-mounted instrumentation (BMI) nozzles of reactor pressure vessels (RPVs) using a qualified volumetric examination method. The inspection is conducted on all susceptible nickel alloy BMI nozzles prior to the subsequent period of extended operation. If this inspection indicates the occurrence of PWSCC, periodic volumetric inspections are performed on these nozzles and adequate inspection periodicity is established. Alternatively, applicant-proposed and staff-approved mitigation methods may be used to manage the aging effect for these components.

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

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

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

   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 Section XI, as incorporated in 10 CFR 50.55a or conform to applicable ASME Code Cases that have been endorsed in 10 CFR 50.55a by referencing the latest version of RG 1.147.

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

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

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

    PWSCC of Alloy 600 components has been observed in domestic and foreign PWRs [NRC Information Notice (IN) 90-10]. The ingress of demineralizer resins also has occurred in operating plants (NRC IN 96-11). The Water Chemistry program, GALL-SLR Report AMP XI.M2, manages the effects of such excursions through monitoring and control of primary water chemistry. NRC Generic Letter (GL) 97-01 is effective in managing the effect of PWSCC. PWSCC also has occurred in the vessel head penetration (VHP) nozzle of U.S. PWRs as described in NRC Bulletins 2001-01, 2002-01 and 2002-02. In addition, PWSCC was observed in reactor vessel BMI nozzles (NRC IN 2003-11, Supplement 1, and licensee event reports (LER) 50-530/2013-001-00).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. 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 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 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.

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

Licensee Event Report 50-530/2013-001-00, “Leakage on Reactor Vessel Bottom-Mounted Instrumentation Nozzle 3.” https://lersearch.inl.gov/LERSearchCriteria.aspx. December 2013.

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

NRC. NRC Inspection Manual, Inspection Procedure 71111.08, “Inservice Inspection Activities.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2015.

_____. NRC 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 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.

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

_____. NRC Regulatory Guide 1.147, Revision 15, “Inservice Inspection Code Case Acceptability.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2004.

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

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

_____. NRC Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity.” Washington, DC: U.S. Nuclear Regulatory Commission. March 2002.

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

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

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 (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI. 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, and percent ferrite. For components for which thermal aging embrittlement is "potentially significant" as defined below, aging management is accomplished through either (a) qualified visual inspections, such as enhanced visual examination (EVT-1); (b) a qualified ultrasonic testing (UT) methodology; or (c) 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 in not significant.

For valve bodies, based on the results of the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, U.S. Nuclear Regulatory Commission (NRC), to Douglas Walters, Nuclear Energy Institute (NEI) (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) fabricated from CASS are not within the scope of this AMP. GALL-SLR Report AMP XI.M9 contains aging management guidance for CASS RVI components of boiling water reactors (BWRs).

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 $^{\circ}$C [482 $^{\circ}$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.

   Based on the criteria set forth in the May 19, 2000, NRC letter, the potential significance of thermal aging embrittlement of CASS materials 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 weight percent [wt.%] Mo), only static-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast low-molybdenum steels with ≤20% ferrite and all centrifugal-cast low-molybdenum steels are not susceptible. For high-molybdenum content steels (SA-351 Grades CF3M, CF3MA, and CF8M or other steels with 2.0 to 3.0 wt.% Mo), static-cast steels with >14% ferrite and centrifugal-cast steels with >20% ferrite thermal embrittlement can be potentially significant, (i.e., screens in). For static-cast high-molybdenum steels with ≤14% ferrite and centrifugal-cast high-molybdenum steels with ≤20% ferrite, thermal aging embrittlement is not significant, (i.e. screens out). In the significance 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 fracture toughness value of 255 kilojoules 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 1).

Table XI.M12-1. Thermal Embrittlement Susceptibility

Molybdenum (Mo) Content	Fe Content	Casting Method	Potentially Susceptible (Screens In)	Not Susceptible (Screens Out)
Low or ≤ 0.5 wt.%	>20% ferrite	Static	X	—
Low or ≤ 0.5 wt.%	≤20% ferrite	Static	—	X
Low or ≤ 0.5 wt.%	Any	Centrifugal	—	X
High or 2.0-3.0 wt.%	>14% ferrite	Static	X	—
High or 2.0-3.0 wt.%	>20% ferrite	Centrifugal	X	—
High or 2.0-3.0 wt.%	≤14% ferrite	Static	—	X
High or 2.0-3.0 wt.%	≤20% ferrite	Centrifugal	—	X

For valve bodies, screening for significance of thermal aging embrittlement is not needed [and thus there are no AMR line items]. For valve bodies greater than 4 inches nominal pipe size (NPS), the existing ASME Code, Section XI inspection requirements are adequate. ASME Code, Section XI, Subsection IWB requires only surface examination of valve bodies less than 4 inches NPS. For these 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).

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

3. ***Parameters Monitored or Inspected**:* The 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 1.6 inches or less in thickness, UT may be performed in accordance with the methodology of Code Case N-824. For CASS piping greater than 1.6 inches in thickness, current UT methodology cannot reliably detect and size cracks; thus EVT-1 is used until a qualified UT methodology can be established. A description of EVT-1 is found in Boiling Water Reactor Vessel and Internals Project (BWRVIP)-03 (Revision 6) and Materials Reliability Program (MRP)-228 for PWRs.

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. The most recent version of the ASME Code, Section IX incorporated by reference in 10 CFR 50.55a (2007 edition through 2008 addenda), does not contain any evaluation procedures applicable to CASS with ferrite content ≥ 20 percent. (Nonmandatory Appendix C to the ASME Code, Section XI states that flaw evaluation methods for CASS with ≥ 20 percent ferrite are currently in the course of preparation.) Therefore, methods used for evaluations of flaws detected in CASS piping or components containing ≥ 20 percent ferrite, and methods used for flaw tolerance evaluations of such components, must be approved by the NRC staff on a case-by-case basis until such methods are incorporated into editions of the ASME Code, Section XI or code cases that are incorporated by reference in 10 CFR 50.55a, or in NRC-approved code cases, as documented in the latest revision to Regulatory Guide (RG) 1.147. NUREG/CR–4513, Revision 1 provides methods for predicting the fracture toughness of thermally aged CASS materials with delta ferrite content up to 25 percent.

7. ***Corrective Actions****:* Results that do not meet the acceptance criteria are addressed as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to

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

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

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

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

10. ***Operating Experience**:* The AMP was developed by using research data obtained on 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, "Codes and Standards." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.[1]

_____. ASME 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. 2012.

---

[1] GALL 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, (EPRI TR-105696) “BWR Vessel and Internals Project: Reactor Pressure Vessel and Internals Examination Guidelines.” Revision 6. Palo Alto, California: Electric Power Research Institute. December 2013.

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

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.

Letter from Christopher I. Grimes, U.S. Nuclear Regulatory Commission, License Renewal and Standardization Branch, to Douglas J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-0030, “Thermal Aging Embrittlement of Cast Stainless Steel Components.” ML003717179. May 19, 2000.

Letter from Mark J. Maxin, 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).” ML081500814. June 2008.

NRC. Regulatory Guide 1.147, “Inservice Inspection Code Case Acceptability.” Washington, DC: U.S. Nuclear Regulatory Commission. 2014.

_____. NUREG/CR–4513, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems.” Revision 1. Washington, DC: U.S. Nuclear Regulatory Commission. August 1994.

XI.M16A DELETED

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. The program is based on commitments made in response to the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-08, and relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L[1] for an effective FAC program. The program includes (a) identifying all susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analyses of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) 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. 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.

Evaluation and Technical Basis

1. ***Scope of Program**:* The FAC program, described by the EPRI guidelines in NSAC-202L, includes procedures or administrative controls to assure that structural integrity is maintained for carbon steel piping components containing single- and two-phase flow conditions. This program also includes the pressure retaining portions of pump and valve bodies within these systems. The FAC program was originally outlined in NUREG–1344 and was further described through the NRC GL 89-08. The program may also include components that are subject to wall thinning due to erosion mechanisms such as cavitation, flashing, droplet impingement, or solid particle impingement in various water systems. Since there are no materials that 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**:* The FAC program 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.

3. ***Parameters Monitored or Inspected**:* The aging management program (AMP) monitors the effects of wall thinning due to FAC and erosion mechanisms by measuring

---

[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.

wall thicknesses. In addition, relevant changes in system operating parameters, (e.g., temperature, flow rate, water chemistry, operating time), that result from off-normal or reduced-power operations are considered for their effects on the FAC models. Also, opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation.

4. ***Detection of Aging Effects****:* Degradation of piping and components occurs by wall thinning. For FAC, the inspection program delineated in NSAC-202L includes identification of susceptible locations, as indicated by operating conditions or special considerations. For periods of extended operation beyond 60 years, piping systems that have been excluded from wall thickness monitoring due to operation 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 radiography testing (RT), to quantify the extent of wall thinning. Opportunistic visual inspections of up-stream and down-stream piping and components are performed during periodic pump and valve maintenance or during pipe replacements to assess internal surface conditions. Wall thicknesses are also measured at locations of suspected wall thinning that are identified by internal visual inspections. A representative sample of components is selected based on the most susceptible locations for wall thickness measurements at a frequency in accordance with NSAC-202L guidelines to ensure that degradation is identified and mitigated 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. The extent and schedule of the inspections ensure 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 operating experience. Components in this category may be treated in a manner similar to other “susceptible-not-modeled” lines discussed in NSAC-202L. EPRI 1011231 provides guidance for identifying potential damage locations. EPRI TR-112657 or NUREG/–CR6031 provides additional insights for cavitation. For cavitation, in addition to wall-thinning, the extent-of-condition review may need to consider the consequences of vibrational loading caused by cavitation.

5. ***Monitoring and Trending****:* For FAC, CHECWORKS™ or similar predictive software calculates component wear rates and 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 if additional inspections are needed to ensure that the extent of wall thinning is adequately determined, that 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 if 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 at the next scheduled inspection 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 should not be less than 1.1.

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

   The program includes reevaluation, repair, or replacement of components for which the acceptance criteria are not satisfied, prior to their return to service. For FAC, long-term corrective actions could include adjusting operating parameters or replacing components with FAC-resistant materials. However, if the wear mechanism has not been identified, then the replaced components should remain in the inspection program because FAC-resistant materials do not protect against erosion mechanisms. Furthermore, when carbon steel piping components are replaced with FAC-resistant material, the susceptible components immediately downstream should be monitored to identify any increased wear due to the "entrance effect" as discussed in EPRI 1015072.

   For erosion mechanisms, long-term corrective actions to eliminate the cause could include adjusting operating parameters and/or changing components' geometric designs; however, the effectiveness of these corrective actions should be verified. Periodic monitoring activities should continue for any component replaced with an alternate material, since a material that is completely resistant to erosion mechanisms is not available.

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

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

10. ***Operating Experience**:* Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems [NRC IE Bulletin No. 87-01; NRC Information Notice (IN) 92-35, IN 95-11, IN 2006-08] and in two-phase piping in extraction steam lines (NRC IN 89-53, IN 97-84) and moisture separator reheater and feedwater heater drains (NRC IN 89-53, IN 91-18, IN 93-21, IN 97-84). Observed wall thinning may be due to mechanisms other than FAC or less commonly, due to a combination of mechanisms [NRC IN 99-19, LER 483/1999-003, licensee event reports (LER) 499/2005-004, LER 277/2006-003, LER 237/2007-003, LER 254/2009-004]. Vibrational loading resulting from cavitation has caused problems (LER 366/2008-001, LER 499/2010-001).

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. EPRI 1015072, “Flow-Accelerated Corrosion–The Entrance Effect.” Palo Alto, California: Electric Power Research Institute. November 2007.

_____. 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 TR-112657, “Revised Risk-Informed Inservice Inspection Evaluation Procedure.” Revision B-A. ML013470102. Palo Alto, California: Electric Power Research Institute. December 1999.

Licensee Event Report 499/2010-001, “South Texas Project Unit 2, Essential Service Water System Leak.” ML100710689. https://lersearch.inl.gov/LERSearchCriteria.aspx. March 2010.

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.” ML093170206. https://lersearch.inl.gov/LERSearchCriteria.aspx. November 2009.

Licensee Event Report 366/2008-001, Hatch Unit 2, “Leak in Vent Pipe to Process Pipe Half Coupling in RHRSW System.” ML081370590. https://lersearch.inl.gov/LERSearchCriteria.aspx. May 2008.

Licensee Event Report 237/2007-003, “Dresden Unit 2, High Pressure Coolant Injection System Declared Inoperable.” ML072750663. https://lersearch.inl.gov/LERSearchCriteria.aspx. September 2007.

Licensee Event Report 277/2006-003, “Peach Bottom Unit 2, Elbow Leak on Piping Attached to Suppression Pool Results in Loss of Containment Integrity.” ML063420059. December 2006

Licensee Event Report 499/2005-004, “South Texas Project Unit 2, Inoperability of Essential Cooling Water 2A and 2B Trains.” ML053410155. https://lersearch.inl.gov/LERSearchCriteria.aspx. November 2005

Licensee Event Report 483/1999-003, “Callaway, Manual Reactor Trip due to Heater Drain System Pipe Rupture Caused by Flow Accelerated Corrosion.” ML003712775. https://lersearch.inl.gov/LERSearchCriteria.aspx. May 2000.

NSAC. NSAC-202L-R4, “Recommendations for an Effective Flow-Accelerated Corrosion Program (3002000563).” Palo Alto, California: Electric Power Research Institute, Nuclear Safety Analysis Center (NSAC). November 2013.

_____. NSAC-202L-R3, “Recommendations for an Effective Flow-Accelerated Corrosion Program.” (1011838). Palo Alto, California: Electric Power Research Institute, Nuclear Safety Analysis Center (NSAC). May 2006.

_____. NSAC-202L-R2, “Recommendations for an Effective Flow-Accelerated Corrosion Program.” Palo Alto, California: Electric Power Research Institute, Nuclear Safety Analysis Center (NSAC). April 1999.

NRC. NRC License Renewal Interim Staff Guidance 2012-01, “Wall Thinning Due to Erosion Mechanisms.” ADAMS Accession No. 12352A057. Washington, DC: U.S. Nuclear Regulatory Commission. April 2013.

_____. NRC Information Notice 2006-08, “Secondary Piping Rupture at the Mihama Power Station in Japan.” Washington, DC: U.S. Nuclear Regulatory Commission. March 2006.

_____. NRC Information Notice 99-19, “Rupture of the Shell Side of a Feedwater Heater at the Point Beach Nuclear Plant.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1999.

_____. NRC Information Notice 97-84, “Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion.” Washington, DC: U.S. Nuclear Regulatory Commission. December 1997.

_____. NRC Information Notice 95-11, “Failure of Condensate Piping Because of Erosion/Corrosion at a Flow Straightening Device.” Washington, DC: U.S. Nuclear Regulatory Commission. February 1995.

_____. NRC Information Notice 93-21, “Summary of NRC Staff Observations Compiled During Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1993.

_____. NUREG/CR-6031, “Cavitation Guide for Control Valves.” Washington DC: U.S. Nuclear Regulatory Commission. April 1993.

_____. NRC Information Notice 92-35, “Higher than Predicted Erosion/Corrosion in Unisolable Reactor Coolant Pressure Boundary Piping inside Containment at a Boiling Water Reactor.” Washington, DC: U.S. Nuclear Regulatory Commission. May 1992.

_____. NRC Information Notice 91-18, “High-Energy Piping Failures Caused by Wall Thinning.” Supplement 1. Washington, DC: U.S. Nuclear Regulatory Commission. December 1991.

_____. NRC Information Notice 91-18, “High-Energy Piping Failures Caused by Wall Thinning.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1991.

_____. NRC Information Notice 89-53, “Rupture of Extraction Steam Line on High Pressure Turbine.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1989.

_____. NRC Generic Letter 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning.” Washington, DC: U.S. Nuclear Regulatory Commission. May 1989.

_____. NUREG–1344, “Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. April 1989.

_____. NRC IE Bulletin 87-01, “Thinning of Pipe Walls in Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1987.

XI.M18 BOLTING INTEGRITY

Program Description

The program manages aging of closure bolting for pressure retaining components. The program relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG–1339, and industry recommendations, as delineated in the following documents:

- NUREG–1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants.”
- Electric Power Research Institute (EPRI) NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants” (with the exceptions noted in NUREG–1339 for safety-related bolting).
- EPRI Report 1015336, “Nuclear Maintenance Application Center: Bolted Joint Fundamentals.”
- EPRI Report 1015337, “Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints.”

The program generally includes periodic inspection of closure bolting for indication of loss of preload, cracking, and loss of material due to corrosion, rust, etc. The program also includes preventive measures to preclude or minimize loss of preload and cracking.

Aging Management Program (AMP) XI.M1, “ASME Section XI ISI, Subsections IWB, IWC, and IWD,” includes inspection of safety-related and nonsafety-related closure bolting and supplements this bolting integrity program. AMPs XI.S1, “ASME Section XI, Subsection IWE,” XI.S3, “ASME Section XI, Subsection IWF,” XI.S6, “Structures Monitoring,” XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” and XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems,” manage inspection of safety-related and nonsafety-related structural bolting.

Evaluation and Technical Basis

1. ***Scope of Program**:* This program manages the effects of aging of closure bolting for pressure retaining components within the scope of license renewal, including both safety-related and nonsafety-related bolting. 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 is in accordance with the guidelines of EPRI Reports 1015336 and 1015337 and the additional recommendations of NUREG–1339 to prevent or mitigate stress corrosion cracking (SCC). Of particular note, use of molybdenum disulfide (MoS_2) as a lubricant has been shown to be a potential contributor to SCC and should not be used. Preventive measures also include using bolting material that has an actual measured yield strength limited to less than 1,034 megapascals (MPa) [150 kilo-pounds per square inch (ksi)]. 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 bolting. Specifically, bolting for safety-related pressure retaining components is inspected for leakage, surface discontinuities and imperfections, and clearances and physical displacements for signs of loose joints. Bolting for other pressure retaining components is inspected for signs of leakage. High strength closure bolting {with actual yield strength greater than or equal to 1,034 MPa [150 ksi]}, and bolting for which yield strength is unknown, should be monitored for surface and subsurface discontinuities indicative of cracking.

4. ***Detection of Aging Effects****:* The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program implements inspection of Class 1, Class 2, and Class 3 pressure retaining bolting in accordance with requirements of ASME Code Section XI,[1] Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. These include volumetric and visual (VT-1) examinations, as appropriate. In addition, for both ASME Code class bolting and non ASME Code class bolting, periodic system walkdowns and inspections (at least once per refueling cycle) ensure detection of leakage at bolted joints before the leakage becomes excessive. Bolting inspections should include consideration of the guidance applicable for pressure boundary bolting in NUREG–1339 and in EPRI NP-5769.

   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 inspection of pressure boundary components for signs of leakage ensures that age-related degradation of closure bolting is detected and corrected before component leakage becomes excessive. Accordingly, pressure retaining bolted connections should be inspected 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 an external surfaces monitoring program.

   Bolting in locations that preclude detection of joint leakage, such as in submerged environments, 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. At a minimum, in each 10-year period during the subsequent period of extended operation, the program includes the inspection of 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. 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. 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. In order to conduct 17 or 19 inspections at a unit in lieu of 25, the

---

[1] Refer to the GALL-SLR Report, Chapter I, for applicability of other editions of the ASME Code, Section XI.

applicant states in the subsequent license renewal application (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 which have had an out-of-spec water chemistry condition for a longer period of time or out-of-spec conditions 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 source from different sources where one or the other is more susceptible to microbiologically-induced corrosion or other aging effects?

When bolting is associated with submerged pumps, pump performance monitoring (e.g., operator walkdowns to confirm sump drainage) provides additional assurance of the integrity of bolted joints.

High strength closure bolting (with actual yield strength greater than or equal to 1,034 MPa [150 ksi] may be subject to SCC. For bolting with yield strength greater than or equal to 1,034 MPa [150 ksi] and bolting for which yield strength is unknown (regardless of code classification or size of bolting), volumetric examination in accordance to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, should be performed.

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 offset, and cleaning processes that ensure an adequate examination.

5. ***Monitoring and Trending****:* The inspection schedules of ASME Section XI components are effective and ensure timely detection of applicable aging effects. If a bolting connection for pressure retaining components not covered by ASME Section XI is reported to be leaking, it may be inspected daily or in accordance with the corrective action process. If the leak rate is increasing, more frequent inspections may be warranted.

6. ***Acceptance Criteria****:* Any indications of aging effects in ASME pressure retaining bolting are evaluated in accordance with Section XI of the ASME Code. For other pressure retaining bolting, indications of aging should be dispositioned in accordance with the corrective action process.

7. ***Corrective Actions****:* Results that do not meet the acceptance criteria are addressed as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to

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

Replacement of ASME pressure retaining bolting is performed in accordance with appropriate requirements of Section XI of the ASME Code, as subject to the additional guidelines and recommendations of EPRI Reports 1015336 and 1015337. Replacement of other pressure retaining bolting (i.e., non-ASME Code class bolting) is performed in accordance with the guidelines and recommendations of EPRI Reports 1015336 and 1015337.

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

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

10. ***Operating Experience**:* Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, SCC, and fatigue loading [NRC IE Bulletin 82-02, NRC Generic Letter (GL) 91-17]. SCC has occurred in high strength bolts used for nuclear steam supply system component supports (EPRI NP-5769). The bolting integrity program developed and implemented in accordance with the applicant's docketed responses to the U.S. Nuclear Regulatory Commission (NRC) communications on bolting events have provided an effective means of ensuring bolting reliability. These programs are documented in EPRI Reports NP-5769, 1015336, and 1015337 and represent industry consensus.

Degradation related failures have occurred in downcomer tee-quencher bolting in boiling water reactors (BWRs) designed with drywells (ADAMS Accession Number ML050730347). Leakage from bolted connections has been observed in reactor building closed cooling systems of BWRs (licensee event report (LER) 50-341/2005-001).

SCC of A-286 stainless steel (SS) closure bolting has occurred when seal cap enclosures have been installed to mitigate gasket leakage at valve body-to-bonnet joints [(NRC Information Notice (IN) 2012-15]. The enclosures surrounding the bolts filled with hot reactor coolant that had leaked from the joint and mixed with the oxygen-containing atmosphere trapped within the enclosure. The enclosures did not allow for inspections of the bolted joints.

The applicant is to evaluate applicable operating experience 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 operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, "Codes and Standards." Washington DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013. [2]

EPRI. EPRI 1015337, "Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints." Palo Alto, California: Electric Power Research Institute. December 2007.

_____. EPRI 1015336, "Nuclear Maintenance Application Center: Bolted Joint Fundamentals." Palo Alto, California: Electric Power Research Institute. December 2007.

_____. 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.

NRC. NRC Information Notice 2012-15, "Use of Seal Cap Enclosures to Mitigate Leakage From Joints That Use A-286 Bolts." Washington, DC: U.S. Nuclear Regulatory Commission. August 2012.

_____. NRC Morning Report, "Failure of Safety/Relief Valve Tee-Quencher Support Bolts." ADAMS Accession Number ML050730347. Washington, DC: U.S. Nuclear Regulatory Commission. March 14, 2005.

_____. NRC Generic Letter 91-17, "Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. October 1991.

_____. NUREG–1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. June 1990.

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

---

[2] 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.

XI.M19 STEAM GENERATORS

Program Description

The Steam Generator program is applicable to managing the aging of steam generator tubes, plugs, sleeves, and secondary side components that are contained within the steam generator (i.e., secondary side internals).

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 TSs at each pressurized water reactor (PWR) contains the same fundamental requirements as outlined in the standard TS of NUREG–1430, Volume 1, Revision 4, for Babcock & Wilcox (B&W) PWRs; NUREG–1431, Volume 1, Revision 4, for Westinghouse PWRs; and NUREG–1432, Volume 1, Revision 4, for Combustion Engineering PWRs. The requirements pertaining to steam generators in these three versions of the standard TSs 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 tubes, plugs, sleeves, and secondary side internals are intended to identify components (e.g., tubes, plugs) with degradation that may need to be removed from service or repaired.

The Steam Generator program at PWRs is modeled after Nuclear Energy Institute (NEI) 97-06, Revision 3, "Steam Generator Program Guidelines." This program references a number of industry guidelines (e.g., the Electric Power Research Institute (EPRI) PWR Steam Generator Examination Guidelines, PWR Primary-to-Secondary Leak Guidelines, PWR Primary Water Chemistry Guidelines, PWR Secondary Water Chemistry Guidelines, Steam Generator Integrity Assessment Guidelines, Steam Generator *In Situ* Pressure Test Guidelines) and incorporates a balance of prevention, mitigation, inspection, evaluation, repair, and leakage monitoring measures. The NEI 97-06 document (a) includes performance criteria that are intended to provide assurance that tube integrity is being maintained consistent with the plant's licensing basis and (b) 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 internals. Therefore, all of these components are addressed by this aging management program (AMP). The NEI 97-06 program has been effective in managing the aging effects associated with steam generator tubes, plugs, sleeves, and secondary side internals.

Evaluation and Technical Basis

1. ***Scope of Program**:* This program addresses degradation associated with steam generator tubes, plugs, sleeves, and secondary side components that are contained within the steam generator (i.e., secondary side internals). It does not cover degradation associated with the steam generator shell, channel head, nozzles, or welds associated with these components.

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 to inhibit wear degradation and secondary side maintenance activities, such as sludge lancing, for removing deposits that may contribute to degradation. Guidance on foreign material exclusion is provided in NEI 97-06. Guidance on maintenance of secondary side integrity is provided in the EPRI Steam Generator Integrity Assessment Guidelines. Primary side preventive maintenance activities include replacing plugs made with corrosion susceptible materials with more corrosion resistant materials and preventively plugging tubes susceptible to degradation.

Extensive deposit buildup in the steam generators could affect tube integrity. The EPRI Steam Generator Integrity Assessment Guidelines, which are referenced in NEI 97-06, provide guidance on maintaining the secondary side of the steam generator, including secondary side cleaning. Secondary side water chemistry plays an important role in controlling the introduction of impurities into the steam generator and potentially limiting their deposition on the tubes. Maintaining high water purity reduces susceptibility to stress corrosion cracking (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 Generic Aging Lessons Learned for Subsequent License Renewal (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: (i) mill annealed Alloy 600, (ii) thermally treated Alloy 600, and (iii) 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, and secondary side internals have also been observed, depending, in part, on the material of construction of the specific component.

   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, dependent on whether a depth-based or voltage-based tube repair criteria (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 as discussed in GALL-SLR Report AMP XI.M2. The EPRI PWR Steam Generator Primary-to-Secondary Leakage

Guidelines (EPRI 1008219) provides guidance on monitoring primary-to-secondary leakage. The EPRI Steam Generator Integrity Assessment Guidelines (EPRI 1019038) provide guidance on secondary side activities.

In summary, the NEI 97-06 program provides guidance on parameters to be monitored or inspected.

4. ***Detection of Aging Effects****:* The TSs require that a Steam Generator program be established and implemented to ensure that steam generator tube integrity is maintained. This requirement ensures that 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 should 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 and secondary side components) may be monitored visually, and, subsequently, more detailed inspections may be performed if degradation is detected.

   NEI 97-06 provides additional guidance on inspection programs to detect 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 1013706) contains guidance on the qualification of steam generator tube inspection techniques.

   The primary-to-secondary leakage monitoring program provides a potential indicator of a loss of steam generator tube integrity. NEI 97-06 and the associated EPRI guidelines provide information pertaining to an effective leakage monitoring program.

5. ***Monitoring and Trending****:* Condition monitoring assessments are performed to determine whether the structural- and accident-induced leakage performance criteria were satisfied during the prior operating interval. Operational assessments are performed to verify that structural and leakage integrity will be maintained for the planned operating interval before the next inspection. If tube integrity cannot be maintained for the planned operating interval before the next inspection, corrective actions are taken in accordance with the plant’s corrective action program. Comparisons of the results of the condition monitoring assessment to the predictions of the previous operational assessment are performed to evaluate the adequacy of the previous operational assessment methodology. If the operational assessment was not conservative in terms of the number and/or severity of the condition, corrective actions are taken in accordance with the plant’s corrective action program.

The TSs require condition monitoring and operational assessments to be performed (although the TSs do not explicitly require operational assessments, these assessments are necessary to ensure that the tube integrity will be maintained until the next inspection). Condition monitoring and operational assessments are done in accordance with the TS requirements and guidance in NEI 97-06 and the EPRI Steam Generator Integrity Assessment Guidelines.

The goal of the inspection program for all components covered by this AMP is to ensure that the components continue to function consistent with the design and licensing basis of the facility (including regulatory safety margins).

Assessments of the degradation of steam generator secondary side internals are performed in accordance with the guidance in the EPRI Steam Generator Integrity Assessment Guidelines to ensure the components continue to function consistent with the design and licensing basis and to ensure TS requirements are satisfied.

6. ***Acceptance Criteria****:* Assessment of tube and sleeve integrity and plugging or repair criteria of flawed and sleeved tubes is in accordance with plant TSs. The criteria for plugging or repairing steam generator tubes and sleeves are based on the U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.121 and are incorporated into plant TSs. Guidance on assessing the acceptability of flaws is also provided in NEI 97-06 and the associated EPRI guidelines, including the EPRI Steam Generator *In-Situ* Pressure Test Guidelines and EPRI Steam Generator Integrity Assessment Guidelines.

   Degraded plugs, degraded secondary side internals, and leaving a loose part or a foreign object in the steam generator are evaluated for continued acceptability on a case-by-case basis. NEI 97-06 and the associated EPRI guidelines provide guidance on the performance of these evaluations. The intent of these evaluations is to ensure that the components affected by parts or objects have adequate integrity consistent with the design and licensing basis of the facility.

   Guidance on the acceptability of primary-to-secondary leakage and water chemistry parameters also are discussed in NEI 97-06 and the associated EPRI guidelines.

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

   For degradation of steam generator tubes and sleeves (if applicable), the TSs provide requirements on the actions to be taken when the acceptance criteria are not met. For degradation of other components, the appropriate corrective action is evaluated per NEI 97-06 and the associated EPRI guidelines, the American Society of Mechanical

Engineers (ASME) Code Section XI,[1] 10 CFR 50.65, and 10 CFR Part 50, Appendix B, as appropriate.

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

   The adequacy of the preventive measures in the Steam Generator program is confirmed through periodic inspections.

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

10. ***Operating Experience**:* Several generic communications have been issued by the NRC related to the steam generator programs implemented at plants. The reference section lists many of these generic communications. In addition, NEI 97-06 provides guidance to the industry for routinely sharing pertinent steam generator operating experience and for incorporating lessons learned from plant operation into guidelines referenced in NEI 97-06. The latter includes providing interim guidance to the industry, when needed.

    The NEI 97-06 program has been effective at managing the aging effects associated with steam generator tubes, plugs, sleeves, and secondary side components that are contained within the steam generator (i.e., secondary side internals), such that the steam generators can perform their intended safety function.

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR 50.55a, "Codes and Standards." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

---

[1]Refer to the GALL-SLR Report, Chapter I, for applicability of other editions of the ASME Code, Section XI.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.[2]

EPRI. EPRI 1019038, “Steam Generator Integrity Assessment Guidelines: Revision 3.” Palo Alto, California: Electric Power Research Institute. November 2009.

_____. EPRI 1016555, “Pressurized Water Reactor Secondary Water Chemistry Guidelines: Revision 7.” Palo Alto, California: Electric Power Research Institute. February 2009.

_____. EPRI 1014986, “Pressurized Water Reactor Primary Water Chemistry Guidelines: Revision 6.” Palo Alto, California: Electric Power Research Institute. December 2007.

_____. EPRI 1014983, “Steam Generator *In-Situ* Pressure Test Guidelines: Revision 3.” Palo Alto, California: Electric Power Research Institute. August 2007.

_____. EPRI 1013706, “PWR Steam Generator Examination Guidelines: Revision 7.” Palo Alto, California: Electric Power Research Institute. October 2007.

_____. EPRI 1008219, “PWR Primary-to-Secondary Leak Guidelines: Revision 3.” Palo Alto, California: Electric Power Research Institute. December 2004.

NEI. NEI 97-06, “Steam Generator Program Guidelines.” Rev. 3. Washington, DC: Nuclear Energy Institute. January 2011.

NRC. NRC Information Notice 2013-20, “Steam Generator Channel Head and Tubesheet Degradation.” Washington DC: U.S. Nuclear Regulatory Commission. July 2013.

_____. NRC Information Notice 2013-11, “Crack-Like Indications at Dents/Dings and in the Freespan Region of Thermally Treated Alloy 600 Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. July 2013.

_____. NRC Information Notice 2012-07, “Tube-To-Tube Contact Resulting in Wear in Once-Through Steam Generators.” Washington DC: U.S. Nuclear Regulatory Commission. July 2012.

_____. NUREG–1432, “Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors.” Volume 1, Rev. 4. Washington DC: U.S. Nuclear Regulatory Commission. April 2012.

_____. NUREG–1431, “Standard Technical Specifications for Westinghouse Pressurized Water Reactors.” Volume 1, Rev 4. Washington DC: U.S. Nuclear Regulatory Commission. April 2012.

[2]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.

_____. NUREG–1430, “Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors.” Volume 4, Rev 3. Washington DC: U.S. Nuclear Regulatory Commission. April 2012.

_____. NRC Information Notice 2010-21, “Crack-Like Indication in the U-Bend Region of a Thermally Treated Alloy 600 Steam Generator Tube.” Washington DC: U.S. Nuclear Regulatory Commission. October 2010.

_____. NRC Information Notice 2010-05, “Management of Steam Generator Loose Parts and Automated Eddy Current Data Analysis.” Washington DC: U.S. Nuclear Regulatory Commission. February 2010.

_____. NRC Regulatory Issue Summary 2009-04, “Steam Generator Tube Inspection Requirements.” Washington DC: U.S. Nuclear Regulatory Commission. April 2009.

_____. NRC Information Notice 2008-07, “Cracking Indications in Thermally Treated Alloy 600 Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. April 2008.

_____. NRC Information Notice 2007-37, “Buildup of Deposits in Steam Generators.” Washington DC: U.S. Nuclear Regulatory Commission. November 2007.

_____. NRC Regulatory Issue Summary 2007-20, “Implementation of Primary-to-Secondary Leakage Performance Criteria.” Washington DC: U.S. Nuclear Regulatory Commission. August 2007.

_____. NRC Generic Letter 2006-01, “Steam Generator Tube Integrity and Associated Technical Specifications.” Washington DC: U.S. Nuclear Regulatory Commission. January 2006.

_____. NRC Information Notice 2005-29, “Steam Generator Tube and Support Configuration.” U.S. Nuclear Regulatory Commission. October 2005.

_____. NRC Information Notice 2005-09, “Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds.” Washington DC: U.S. Nuclear Regulatory Commission. April 2005.

_____. NRC Information Notice 2004-17, “Loose Part Detection and Computerized Eddy Current Data Analysis in Steam Generators.” Washington DC: U.S. Nuclear Regulatory Commission. August 2004.

_____. NRC Information Notice 2004-16, “Tube Leakage Due to a Fabrication Flaw in a Replacement Steam Generator.” Washington DC: U.S. Nuclear Regulatory Commission. August 2004.

_____. NRC Information Notice 2004-10, “Loose Parts in Steam Generators.” Washington DC: U.S. Nuclear Regulatory Commission. May 2004.

_____. NRC Generic Letter 2004-01, “Requirements for Steam Generator Tube Inspections.” Washington DC: U.S. Nuclear Regulatory Commission. August 2004.

_____. NRC Information Notice 2003-13, “Steam Generator Tube Degradation at Diablo Canyon.” Washington DC: U.S. Nuclear Regulatory Commission. August 2003.

_____. NRC Information Notice 2003-05, “Failure to Detect Freespan Cracks in PWR Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. June 2003.

_____. NRC Information Notice 2002-21, “Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing.” Supplement 1. Washington DC: U.S. Nuclear Regulatory Commission. April 2003.

_____. NRC Information Notice 2002-21, “Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing.” Washington DC: U.S. Nuclear Regulatory Commission. June 2002.

_____. NRC Information Notice 2002-02, “Recent Experience with Plugged Steam Generator Tubes.” Supplement 1. Washington DC: U.S. Nuclear Regulatory Commission. July 2002.

_____. NRC Information Notice 2002-02, “Recent Experience with Plugged Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. January 2002.

_____. NRC Information Notice 2001-16, “Recent Foreign and Domestic Experience with Degradation of Steam Generator Tubes and Internals.” Washington DC: U.S. Nuclear Regulatory Commission. October 2001.

_____. NRC Regulatory Issue Summary 2000-22, “Issues Stemming from NRC Staff Review of Recent Difficulties Experienced in Maintaining Steam Generator Tube Integrity.” Washington DC: U.S. Nuclear Regulatory Commission. November 2000.

_____. NRC Information Notice 2000-09, “Steam Generator Tube Failure at Indian Point Unit 2.” Washington DC: U.S. Nuclear Regulatory Commission. June 2000.

_____. NRC Information Notice 98-27, “Steam Generator Tube End Cracking.” Washington DC: U.S. Nuclear Regulatory Commission. July 1998.

_____. NRC Draft Regulatory Guide DG-1074, “Steam Generator Tube Integrity.” Washington DC: U.S. Nuclear Regulatory Commission. December 1998.

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

_____. NRC Information Notice 97-79, “Potential Inconsistency in the Assessment of the Radiological Consequences of a Main Steam Line Break Associated with the Implementation of Steam Generator Tube Voltage-Based Repair Criteria.” Washington DC: U.S. Nuclear Regulatory Commission. November 1997.

_____. NRC Information Notice 97-49, “B&W Once-Through Steam Generator Tube Inspection Findings.” Washington DC: U.S. Nuclear Regulatory Commission. July 1997.

_____. NRC Information Notice 97-26, “Degradation in Small-Radius U-Bend Regions of Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. May 1997.

_____. NRC Generic Letter 97-06, “Degradation of Steam Generator Internals.” Washington DC: U.S. Nuclear Regulatory Commission. December 1997.

_____. NRC Information Notice 96-38, “Results of Steam Generator Tube Examinations.” Washington DC: U.S. Nuclear Regulatory Commission. June 1996.

_____. NRC Information Notice 96-09, “Damage in Foreign Steam Generator Internals.” Supplement 1. Washington DC: U.S. Nuclear Regulatory Commission. July 1996.

_____. NRC Information Notice 96-09, “Damage in Foreign Steam Generator Internals.” Washington DC: U.S. Nuclear Regulatory Commission. February 1996.

_____. NRC Information Notice 95-40, “Supplemental Information to Generic Letter 95-03, Circumferential Cracking of Steam Generator Tubes.” U.S. Nuclear Regulatory Commission. September 1995.

_____. NRC Generic Letter 95-05, “Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking.” Washington DC: U.S. Nuclear Regulatory Commission. August 1995.

_____. NRC Generic Letter 95-03, “Circumferential Cracking of Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. April 1995.

_____. NRC Information Notice 94-88, “Inservice Inspection Deficiencies Result in Severely Degraded Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. December 1994.

_____. NRC Information Notice 94-87, “Unanticipated Crack in a Particular Heat of Alloy 600 Used for Westinghouse Mechanical Plugs for Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. December 1994.

_____. NRC Information Notice 94-62, “Operational Experience on Steam Generator Tube Leaks and Tube Ruptures.” Washington DC: U.S. Nuclear Regulatory Commission. August 1994.

_____. NRC Information Notice 94-43, “Determination of Primary-to-Secondary Steam Generator Leak Rate.” Washington DC: U.S. Nuclear Regulatory Commission. June 1994.

_____. NRC Information Notice 94-05, “Potential Failure of Steam Generator Tubes Sleeved With Kinetically Welded Sleeves.” Washington DC: U.S. Nuclear Regulatory Commission. January 1994.

_____. NRC Information Notice 93-56, “Weaknesses in Emergency Operating Procedures Found as a Result of Steam Generator Tube Rupture.” Washington DC: U.S. Nuclear Regulatory Commission. July 1993.

_____. NRC Information Notice 93-52, Draft NUREG–1477, “Voltage-Based Interim Plugging Criteria for Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. July 1993.

_____. NRC Information Notice 92-80, “Operation with Steam Generator Tubes Seriously Degraded.” Washington DC: U.S. Nuclear Regulatory Commission. December 1992.

_____. NRC Information Notice 91-67, “Problems with the Reliable Detection of Intergranular Attack (IGA) of Steam Generator Tubing.” Washington DC: U.S. Nuclear Regulatory Commission. October 1991.

_____. NRC Information Notice 91-43, “Recent Incidents Involving Rapid Increases in Primary-to-Secondary Leak Rate.” Washington DC: U.S. Nuclear Regulatory Commission. July 1991.

_____. NRC Information Notice 91-19, “Steam Generator Feedwater Distribution Piping Damage.” Washington DC: US Nuclear Regulatory Commission. March 1991.

_____. NRC Bulletin 89-01, “Failure of Westinghouse Steam Generator Tube Mechanical Plugs.” Supplement 2. Washington DC: U.S. Nuclear Regulatory Commission. June 1991.

_____. NRC Information Notice 90-49, “Stress Corrosion Cracking in PWR Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. August 1990.

_____. NRC Bulletin 89-01, “Failure of Westinghouse Steam Generator Tube Mechanical Plugs.” Supplement 1. Washington DC: U.S. Nuclear Regulatory Commission. November 1990.

_____. NRC Information Notice 89-65, “Potential for Stress Corrosion Cracking in Steam Generator Tube Plugs Supplied by Babcock and Wilcox.” Washington DC: U.S. Nuclear Regulatory Commission. September 1989.

_____. NRC Bulletin 89-01, “Failure of Westinghouse Steam Generator Tube Mechanical Plugs.” Washington, DC: U.S. Nuclear Regulatory Commission. May 1989.

_____. NRC Information Notice 88-99, “Detection and Monitoring of Sudden and/or Rapidly Increasing Primary-to-Secondary Leakage.” Washington DC: U.S. Nuclear Regulatory Commission. December 1988.

_____. NRC Information Notice 88-06, “Foreign Objects in Steam Generators.” Washington DC: U.S. Nuclear Regulatory Commission. February 1988.

_____. NRC Bulletin 88-02, “Rapidly Propagating Cracks in Steam Generator Tubes.” Washington, DC: U.S. Nuclear Regulatory Commission. February 1988.

_____. NRC Information Notice 85-37, “Chemical Cleaning of Steam Generators at Millstone 2.” U.S. Nuclear Regulatory Commission. May 1985.

_____. NRC Regulatory Guide, 1.121, “Bases for Plugging Degraded PWR Steam Generator Tubes.” Washington DC: U.S. Nuclear Regulatory Commission. August 1976.

XI.M20 OPEN-CYCLE COOLING WATER SYSTEM

Program Description

The program relies, in part, on implementing portions of the recommendations for the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-13 to ensure that the effects of aging on the open-cycle cooling water (OCCW) (or service water) system will be managed for the 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 is comprised of the aging management aspects of the applicant's response to NRC GL 89-13 including: (a) a program of surveillance and control techniques to preclude biofouling; (b) a program to verify heat transfer capabilities of all safety-related heat exchangers cooled by the OCCW system; and (c) a program for routine inspection and maintenance to ensure that corrosion, erosion, loss of coating integrity, fouling, and biofouling cannot degrade the performance of safety-related systems serviced by the OCCW system. Since 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 to ensure aging effects are adequately managed.

The OCCW system program manages 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 include: (a) surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and fouling in the OCCW system or structures and components (SCs) serviced by the OCCW system; (b) inspection of components for signs of corrosion, erosion, loss of coating or lining integrity, fouling, and biofouling; and (c) testing of the heat transfer capability of heat exchangers that remove heat from components important to safety.

For buried OCCW system piping, the aging effects on the external surfaces are managed by XI.M41, "Buried and Underground Piping and Tanks," but the internal surfaces are managed by this program. The aging management of closed-cycle cooling water (CCCW) systems is described in 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 XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." However, water systems for fire protection are managed by XI.M27, "Fire Water System." The loss of coating or lining integrity for components managed by this program may be managed by XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks." Otherwise, if the OCCW system program manages internal coatings or linings, the program includes comparable guidance as provided in XI.M42.

Evaluation and Technical Basis

1. ***Scope of Program**:* The 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 also applies to internal coatings or linings of OCCW system piping and components that are not being separately managed by a coatings monitoring program. 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; however, 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-induced corrosion 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 lining may be included.

3. ***Parameters Monitored or Inspected**:* This program addresses loss of material, fouling, and in some materials, cracking. This program: (a) inspects surfaces of components exposed to raw water for presence of fouling; (b) monitors heat transfer performance of components affected by fouling in the OCCW system; and (c) monitors the condition of piping and components to ensure that loss of material, loss of coating or lining integrity, cracking, and flow blockage do not degrade the performance of the safety-related systems supplied by the OCCW system. For those portions of the OCCW system where flow monitoring is not performed, test results from the monitored portions of the system are used to calculate friction (or roughness) factors and are used to confirm that design flow rates will be achieved with the overall fouling identified in the system. If concrete piping is being managed, American Concrete Institute (ACI) 349.3R provides an acceptable basis for parameters monitored or inspected.

4. ***Detection of Aging Effects**:* Inspection scope, methods (e.g., visual or volumetric inspections, performance testing), and frequencies are in accordance with the applicant's docketed response to NRC GL 89-13. As noted in NRC GL 89-13, testing frequencies can be adjusted to provide assurance that equipment will perform the 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 and provide a qualitative assessment for loss of material due to various forms of corrosion and erosion. Examinations of polymeric materials should be consistent with the examinations described in aging management program (AMP) XI.M38. Volumetric examinations, such as ultrasonic testing (UT), 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 (ASME) Code should follow procedures consistent with the ASME Code. NonASME Code inspections should follow site procedures that include requirements for items such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes that ensure an adequate examination. 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 adequacy of testing frequencies. For heat exchangers that are inspected for degradation in lieu of testing, inspection results are trended to evaluate adequacy of 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 where 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., microbiologically-induced corrosion), 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 next scheduled inspection are greater than the components' minimum wall thickness requirements. As applicable, coatings or linings are intact with no indications of peeling, delaminating, blistering, cracking, flaking, or rusting. For heat exchangers, heat removal capability is within design values. For ongoing degradation mechanisms (e.g., microbiologically-induced corrosion), 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related 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 for reduction of heat transfer or flow blockage is evaluated. Fouling deposits are removed to determine if loss of material has occurred and to prevent further degradation in the system. For ongoing degradation mechanisms (e.g., microbiologically-induced corrosion), the frequency and extent of wall thickness inspections are increased commensurate with the significance of the degradation.

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

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

10. ***Operating Experience**:* Loss of material due to corrosion, including microbiologically-induced corrosion and erosion, has been identified [NRC Information Notice (IN) 85-30, IN 2007-06, licensee event reports (LER) 247/2001-006, LER 306/2004-001, LER 483/2005-002, LER 331/2006-003, LER 255/2007-002, LER 454/2007-002, LER 254/2011-001, LER 255/2013-001, LER 286/2014-002]. Protective coatings have failed, leading to unanticipated corrosion (IN 85-24, IN 2007-06, LER 286/2002-001,

LER 286/2011-003). Reduction in heat transfer and flow blockage due to fouling has occurred in piping and in heat exchangers from protective coating failures, and accumulations of silt and sediment (IN 81-21, IN 86-96, IN 2004-07, IN 2006-17, IN 2007-28, IN 2008-11, LER 413/1999-010, LER 305/2000-007, LER 266/2002-003, LER 413/2003-004, LER 263/2007-004, LER 321/2010-002, LER 457/2011-001, LER 457/2011-002, LER 397/2013-002). Cracking due to stress corrosion cracking (SCC) has occurred in brass tubing (LER 305/2002-002), and pitting in SS has occurred (LER 247/2013-004).

The review of plant-specific operating experience 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 3.2.2.2.8, 3.3.2.2.7, and 3.4.2.2.6, “Loss of Material Due to Recurring Internal Corrosion,” include criteria to identify 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 operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.[1]

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.” ML14087A009. https://lersearch.inl.gov/LERSearchCriteria.aspx. March 2014.

Licensee Event Report 397/2013-002, “Main Control Room Cooler Failed Surveillance.” ML13141A288. https://lersearch.inl.gov/LERSearchCriteria.aspx. May 2013.

Licensee Event Report 255/2013-001, “Technical Specification Required Shutdown Due to a Component Cooling Water System Leak.” ML13100A019. https://lersearch.inl.gov/LERSearchCriteria.aspx. April 2013.

[1]GALL 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 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.” ML13319B082. https://lersearch.inl.gov/LERSearchCriteria.aspx. November 2013.

Licensee Event Report 457/2011-002, “Auxiliary Feedwater System Inoperability Due to Additional Asiatic Clam Shells in Essential Service Water Supply Piping.” ML11263A185. https://lersearch.inl.gov/LERSearchCriteria.aspx. September 2011.

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.” ML112010177. https://lersearch.inl.gov/LERSearchCriteria.aspx. July 2011.

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.” ML11123A165. https://lersearch.inl.gov/LERSearchCriteria.aspx. April 2011.

Licensee Event Report 254/2011-001, “Loss of Both Divisions of Residual Heat Removal System.” ML11174A039. https://lersearch.inl.gov/LERSearchCriteria.aspx. June 2011.

Licensee Event Report 321/2010-002, “Degraded Plant Service Water Cooling to Main Control Room Air Conditioner Results in Loss of Function.” ML101650089. https://lersearch.inl.gov/LERSearchCriteria.aspx. June 2010.

Licensee Event Report 454/2007-002, “Technical Specification Required Shutdown of Unit 1 and Unit 2 Due to an Ultimate Heat Sink Pipe Leak.” ML080660544. https://lersearch.inl.gov/LERSearchCriteria.aspx. March 2008.

Licensee Event Report 263/2007-004, “Degradation of Emergency Service Water Flow to Emergency Core Cooling System Room Cooler.” ML072430882. https://lersearch.inl.gov/LERSearchCriteria.aspx. August 2007.

Licensee Event Report 255/2007-002, “Inoperable Containment Due to Containment Air Cooler Through-Wall Flaw.” ML070871046. https://lersearch.inl.gov/LERSearchCriteria.aspx. March 2007.

Licensee Event Report 331/2006-003, “Residual Heat Removal Service Water Pump Inoperable Due to Motor Cooler Failures.” ML062490486. https://lersearch.inl.gov/LERSearchCriteria.aspx. August 2006.

Licensee Event Report 483/2005-002, “Plant Shutdown Required by Technical Specification 3.7.8 for an Inoperable Train of Essential Service Water.” ML051460343. https://lersearch.inl.gov/LERSearchCriteria.aspx. May 2005.

Licensee Event Report 306/2004-001, “Shutdown Required by Technical Specifications Due to Two Trains of Containment Cooling Inoperable.” ML050890314. https://lersearch.inl.gov/LERSearchCriteria.aspx. March 2005.

Licensee Event Report 413/2003-004, “1A Containment Spray System Inoperable for Longer than Technical Specifications Allow Due to Heat Exchanger Fouling.” ML031970061. https://lersearch.inl.gov/LERSearchCriteria.aspx. July 2003.

Licensee Event Report 266/2002-003, “Possible Common Mode Failure of AFW Due to Partial Clogging of Recirculation Orifices.” ML032890115. https://lersearch.inl.gov/LERSearchCriteria.aspx. October 2003.

Licensee Event Report 305/2002-002, “Technical Specifications Required Shutdown: CCW System Leak Could Not Be Repaired Within LCO.” ML021920465. https://lersearch.inl.gov/LERSearchCriteria.aspx. July 2002.

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.” ML022000155. https://lersearch.inl.gov/LERSearchCriteria.aspx. July 2002.

Licensee Event Report 247/2001-006, “Pipe Erosion Results in Service Water System Leakage in Containment.” ML020090594. https://lersearch.inl.gov/LERSearchCriteria.aspx. December 2001.

Licensee Event Report 305/2000-007, “Alternate Service Water Supply Piping Obstructed.” ML003726758. https://lersearch.inl.gov/LERSearchCriteria.aspx. June 2000

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.” https://lersearch.inl.gov/LERSearchCriteria.aspx. July 1999.

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

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

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

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

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

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

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

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

XI.M21A CLOSED TREATED WATER SYSTEMS

Program Description

Nuclear power plants (NPPs) 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 addition of makeup water (i.e., closed systems). The program includes (a) 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; (b) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation. Depending on the industry standard selected for use in association with this aging management program (AMP) and/or plant operating experience, this program also may include corrosion monitoring (e.g., corrosion coupon testing) and microbiological testing.

The water used in systems covered by this AMP may be, but need not be, demineralized and receives chemical treatment, including corrosion inhibitors, unless the systems meet the industry guidance for pure water systems. Otherwise, untreated water systems are addressed using other AMPs, such as Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (XI.M38). Examples of systems managed by this AMP include closed-cycle cooling water (CCCW) systems (as defined by the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-13[1]); closed portions of heating, ventilation, and air conditioning (HVAC) systems; diesel generator cooling water; and auxiliary boiler systems. Examples of systems not addressed by this AMP include boiling water reactor (BWR) coolant, pressurized water reactor (PWR) primary and secondary water, and PWR/BWR condensate systems. Aging in these systems is managed by the water chemistry AMP (XI.M2) and the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel 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

---

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

program includes corrosion inhibitors and is designed to maintain the function of associated equipment and minimize the corrosivity of the water and the accumulation of corrosion products that can foul heat transfer surfaces.

3. ***Parameters Monitored or Inspected****:* This program monitors water chemistry parameters (preventive monitoring) and the condition of surfaces exposed to the water (condition monitoring). Depending on the industry standard selected for use in association with this AMP and/or plant operating experience, 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 industry standard guidance documents produced by the Electric Power Research Institute (EPRI), the American Society of Heating Refrigeration and Air Conditioning Engineers, the Cooling Technology Institute, the American Boiler Manufacturer's Association, American Society for Testing and Materials (ASTM) standards, water chemistry guidelines recommended by the equipment manufacturer, Nalco Water Handbook, or the ASME. For CCCW systems, as defined in NRC GL 89-13, EPRI 1007820 is used. For other systems, the applicant selects an appropriate industry standard document. In all cases, the selected industry standard guidance document is used in its entirety for the water chemistry control or guidance.

   The visual appearance of surfaces provides evidence of loss of material. Surface discontinuities revealed by surface or volumetric examination techniques provide evidence of cracking. The heat transfer capability of heat exchanger surfaces is evaluated by either visual inspections to determine surface cleanliness, or 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 ensures that the water treatment program is effective in maintaining acceptable water chemistry. Water testing is conducted in accordance with the selected industry standard. The frequency of water testing is in accordance with the selected industry standard, but in no case should the testing interval be greater than quarterly unless justified with a documented analysis.

   Because the control of water chemistry may not be fully effective in mitigating the aging effects, inspections are conducted. Visual inspections of internal surfaces are conducted whenever the system boundary is opened. At a minimum, 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, 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. 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. In order to conduct 17 or 19 inspections at a unit in lieu of 25, the subsequent license renewal application (SLRA) 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?
- Are there any systems which have had an out-of-spec water chemistry condition for a longer period of time or out-of-spec conditions occur more frequently?

If degradation is identified in the initial sample, additional samples are inspected to determine the extent of the condition.

The ongoing opportunistic visual inspections are credited towards 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. For non-ASME Code inspections, the inspections should follow site procedures that include requirements for items such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes that ensure an adequate examination.

5. ***Monitoring and Trending**:* Water chemistry data are evaluated against the standards contained in the selected industry standard documents. These data are trended, so corrective actions are taken, based on trends in water chemistry, prior to loss of intended function. Inspection results also are trended with time so that the progression of any corrosion or cracking can be evaluated and predicted.

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 as conditions adverse to quality or significant conditions adverse to quality under those 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 Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, quality assurance (QA) program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   Water chemistry concentrations that are not in accordance with the selected industry standard document should be returned to an "in specification" condition in accordance with the referenced guidelines. Some industry standard documents have time guidelines which govern how rapidly “out of specification” conditions should be corrected. If fouling is identified, the overall effects on reduction of heat transfer are evaluated. Fouling deposits are removed to determine if loss of material has occurred and to prevent further degradation in the system.

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

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

10. ***Operating Experience****:* Degradation of CCCW systems due to corrosion product buildup [licensee event reports (LER) 327/93-029] or through-wall cracks in supply lines (NRC LER 50-280/91-019-00) has been observed in operating plants. In addition, SCC of stainless steel (SS) reactor recirculation pump seal heat exchanger coils has been attributed to localized boiling of the closed cooling water, concentrating water impurities on the coil surfaces (LER 263/2014-001). Accordingly, operating experience 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 operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.[3]

EPRI 1007820, “Closed Cooling Water Chemistry Guideline.” Palo Alto, California: Electric Power Research Institute. April 2004.

Flynn, Daniel. *The Nalco Water Handbook.* Nalco Company. 2009.

---

[3]GALL 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." ML14073A599. https://lersearch.inl.gov/LERSearchCriteria.aspx. March 2014

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." https://lersearch.inl.gov/LERSearchCriteria.aspx. December 1993.

Licensee Event Report 280/1991-019, "Loss of Containment Integrity due to Crack in Component Cooling Water Piping." https://lersearch.inl.gov/LERSearchCriteria.aspx. October 1991.

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

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

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 aging management of spent fuel pools using Boraflex as the neutron-absorbing material. 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 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 causes 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: (a) 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 (b) 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 physical conditions of the Boraflex panels, such as gap formation and decreased boron-10 areal density, and the concentration of the silica in the spent fuel pool. These are conditions directly related to degradation of the Boraflex material. When Boraflex is subjected to gamma radiation and long-term exposure to the spent fuel pool environment, the silicon polymer matrix becomes degraded and silica filler and boron carbide are released into the spent fuel pool water. As indicated in the U.S. Nuclear Regulatory Commission (NRC) Information Notice (IN) 95-38 and NRC Generic Letter (GL) 96-04, the loss of boron carbide (washout) from Boraflex is characterized by slow dissolution of silica from the surface of the Boraflex and a gradual thinning of the material. Because Boraflex contains about 25 percent silica, 25 percent polydimethyl siloxane polymer, and 50 percent boron carbide, sampling and analysis for the presence of silica in the spent fuel pool provide an indication of 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 ensure that Boraflex panel degradation does not compromise criticality analysis for 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 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 to perform 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 period of extended operation.

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

   Corrective actions are 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 which are available to maintain a subcriticality margin of 5 percent.

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

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

10. ***Operating Experience****:* NRC IN 87-43 addresses the problems of development of tears and gaps (average 1-2 inches, with the largest 4 inches) in Boraflex sheets due to gamma radiation-induced shrinkage of the material. NRC IN 93-70, NRC IN 95-38, and NRC GL 96-04 address several cases of significant degradation of Boraflex test coupons due to accelerated dissolution of Boraflex caused by pool water flow through panel enclosures and high accumulated gamma dose. In such cases, the Boraflex may be replaced by boron steel inserts or by a completely new rack system using Boral®. Experience with boron steel is limited; however, the application of Boral® for use in the spent fuel storage racks predates the manufacturing and use of Boraflex. The experience with Boraflex panels indicates that coupon surveillance programs are not reliable. Therefore, during the 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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 TR-103300, "Guidelines for Boraflex Use in Spent-Fuel Storage Racks." Palo Alto, California: Electric Power Research Institute. December 1993.

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

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

NRC. NRC Generic Letter 96-04, "Boraflex Degradation in Spent Fuel Pool Storage Racks." ML031110008. Washington, DC: U.S. Nuclear Regulatory Commission. June 26, 1996.

NRC. NRC Information Notice 95-38, “Degradation of Boraflex Neutron Absorber in Spent Fuel Storage Racks.” ML031060277. Washington, DC: U.S. Nuclear Regulatory Commission. September 8, 1995.

NRC. NRC Information Notice 93-70, “Degradation of Boraflex Neutron Absorber Coupons.” ML031070107. Washington, DC: U.S. Nuclear Regulatory Commission. September 10, 1993.

_____. NRC Information Notice 87-43, “Gaps in Neutron Absorbing Material in High Density Spent Fuel Storage Racks.” ML031130349. Washington, DC: U.S. Nuclear Regulatory Commission. September 8, 1987.

_____. 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 Regulatory Guide 1.26, Rev. 3, “Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants (for Comment).” ML003739964. Washington, DC: U.S. Nuclear Regulatory Commission. February 29, 1979.

XI.M23 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

Program Description

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program evaluates the effectiveness of maintenance monitoring activities for cranes and hoists that are within the scope of license renewal. This program primarily addresses the structural components that make up the bridge and trolley. 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 on bridge components, rails, and trolley structural components; loss of material due to wear on rails; cracking due to stress corrosion cracking (SCC) of high strength bolts, and loss of preload on bolted connections. NUREG–0612, "Control of Heavy Loads at Nuclear Power Plants," provides specific guidance on the control of overhead heavy load cranes. The aging management activities specified in this program utilize the guidance provided in American Society of Mechanical Engineers (ASME) Safety Standard B30.2, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)" or other appropriate standards in the ASME B30 series.

Evaluation and Technical Basis

1. ***Scope of Program****:* The program manages (a) the effects of loss of material due to general corrosion on the bridge rails, bridge, and trolley structural components for those cranes that are within the scope of 10 CFR 54.4, (b) the effects of wear on the rails in the rail system, and (c) cracking due to SCC of high strength bolts. The program also manages the effects of loss of preload of bolted connections.

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 ensure that loss of material is not occurring due to corrosion or wear. Bolted connections are monitored for loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. High strength [actual measured yield strength greater than 150 kilopounds per square inch (ksi) or 1,034 megapascal (MPa)] bolts greater than 1 inch in diameter are monitored for SCC.

4. ***Detection of Aging Effects****:* Crane rails and structural components are visually inspected at a frequency in accordance ASME B30.2, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)," or other 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. Bolted connections are visually inspected for loose bolts or missing nuts at the same frequency as crane rails and structural components. Visual inspection of high strength (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) structural

bolting greater than 1 in [25 mm] in diameter is supplemented with volumetric or surface examinations to detect cracking at an interval not to exceed 5 years, unless justified.

5. ***Monitoring and Trending**:* Visual inspection activities are performed by personnel qualified in accordance with controlled procedures and processes. Deficiencies are documented using applicant-approved 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 due to corrosion or wear and any visual sign of loss of bolting preload is evaluated according to ASME B30.2 or other applicable industry standard in the ASME B30 series. Volumetric or surface examinations confirm the absence of cracking in high strength bolts.

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

   Repairs are performed as specified in ASME B30.2 or other appropriate standard in the ASME B30 series.

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

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

10. ***Operating Experience**:* There has been no history of corrosion-related degradation that threatened the ability of a crane to perform its intended function. Likewise, because cranes have not been operated beyond their design lifetime, 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 54.4, "Scope." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Safety Standard B30.2, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)." New York, New York: American Society of Mechanical Engineers. 2005.

NRC. NRC Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Revision 2. ML003761662. U.S. Nuclear Regulatory Commission, March 31, 1997.

_____. NRC Generic Letter 81-07, "Control of Heavy Loads." ML031080524. Washington, DC: U.S. Nuclear Regulatory Commission. February 3, 1981.

_____. NRC Generic Letter 80-113, "Control of Heavy Loads." ML071080219. Washington, DC: U.S. Nuclear Regulatory Commission. December 22, 1980.

_____. NUREG–0612, "Control of Heavy Loads at Nuclear Power Plants." ML070250180. Washington, DC: U.S. Nuclear Regulatory Commission. July 31, 1980.

XI.M24 COMPRESSED AIR MONITORING

Program Description

The purpose of the compressed air monitoring program is to provide reasonable assurance of the integrity of the compressed air system. The program consists of monitoring moisture content, corrosion, and performance of the compressed air system. This includes (a) preventive monitoring of water (moisture) and other potential contaminants to keep within the specified limits; and (b) inspection of components for indications of loss of material due to corrosion.

The compressed air monitoring aging management program (AMP) is based on results of the plant owner's response to the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-14 (as applicable to license renewal) and reported in previous NRC Information Notice (IN) 81-38; IN 87-28; IN 87-28, Supplement 1; and by the Institute of Nuclear Power Operations (INPO) Significant Operating Experience Report (SOER) 88-01. NRC GL 88-14, issued after several years of study of problems and failures of instrument air systems, recommends that each holder of an operating license perform an extensive design and operations review and verification of its instrument air system. NRC GL 88-14 also recommends that the licensees describe their program for maintaining proper instrument air quality. This AMP does not include all aspects of NRC GL 88-14 because many of the issues in the GL are not relevant to license renewal.

This AMP does not change the applicant's docketed response to NRC GL 88-14 for the rest of its operations. The program utilizes the aging management aspects of the applicant's response to NRC GL 88-14 for license renewal with regard to preventative measures, inspections of components, and testing to ensure that the compressed air system will be able to perform its intended function for the period of extended operation. The AMP also incorporates the air quality provisions provided in the guidance of the Electric Power Research Institute (EPRI) TR 108147. The American Society of Mechanical Engineers (ASME) operations and maintenance standards and guides (ASME OM-2012, Division 2, Part 28) provides additional guidance for maintenance of the instrument air system by offering recommended test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

Evaluation and Technical Basis

1. ***Scope of Program****:* The program manages the aging effects of loss of material due to corrosion in compressed air systems.

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 ensure that the system and components maintain their intended functions. These limits are prepared from consideration of the manufacturer's recommendations for individual components and guidelines based on ASME OM-2012, Division 2, Part 28; ANSI/ISA-7.0.01-1996; and EPRI TR-108147.

3. ***Parameters Monitored or Inspected****:* Periodic air samples are taken and analyzed for moisture content, lubricant content, particulate matter and other corrosive contaminants and hazardous gases. Periodic and opportunistic inspections of accessible internal surfaces are performed for signs of corrosion and abnormal corrosion products that might indicate a loss of material within the system.

4. ***Detection of Aging Effects****:* The program periodically samples and tests the air in the compressed system in accordance with industry standards (i.e., ANSI/ISA-7.0.01-1996). Compressed air systems have in-line dew point instrumentation that either checks continuously using an automatic alarm system or is checked at least daily to ensure that moisture content is within the recommended range. Additionally, periodic visual inspections of critical component internal surfaces (compressors, dryers, after-coolers, and filters) are performed for signs of loss of material due to corrosion. Guidance for inspection frequency and inspection methods of these components is provided in standards or documents such as ASME OM-2012, Division 2, Part 28.

   Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task.

5. ***Monitoring and Trending****:* If daily readings of system dew points are taken, they are recorded and trended. Air quality analysis results are reviewed to determine if alert levels or limits have been reached or exceeded. This review also checks for unusual trends. ASME OM-2012, Division 2, Part 28, provides guidance for monitoring and trending data. Visual inspection results are compared to previous results to ascertain if adverse long-term trends exist. 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 ANSI/ISA-7.0.01-1996. Internal surfaces should 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 air meets acceptable quality standards.

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

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

9. ***Administrative Controls****:* Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B, associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to

fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10. ***Operating Experience**:* Potentially significant safety-related problems pertaining to air systems have been documented in NRC IN 81-38; IN 87-28; IN 87-28, Supplement 1; and licensee event report (LER) 50-237/94-005-3. Some of the systems that have been significantly degraded or that have failed due to the problems in the air system include the decay heat removal, auxiliary feedwater (AFW), main steam isolation, containment isolation, and fuel pool seal systems. In 2008, one plant incurred an unplanned reactor trip from a failure of a mechanical joint in the instrument air system (NRC IN 2008-06). Nevertheless, as a result of NRC GL 88-14 and in consideration of INPO SOER 88-01 and EPRI TR-108147, performance of air systems has improved significantly.

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

ASME. ASME OM-2012, "Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants." Division 2, Part 28. New York, New York: American Society of Mechanical Engineers. 2012.

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

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

Licensee Event Report 50-237/94-005-3, "Manual Reactor Scram due to Loss of Instrument Air Resulting from Air Receiver Pipe Failure Caused by Improper Installation of Threaded Pipe during Initial Construction." https://lersearch.inl.gov/LERSearchCriteria.aspx. April 3, 1997.

NRC. NRC Information Notice 2008-06, "Instrument Air System Failure Resulting In Manual Reactor Trip." ML073540243. Washington, DC: U.S. Nuclear Regulatory Commission. April 10, 2008.

_____. NRC Generic Letter 88-14, "Instrument Air Supply Problems Affecting Safety-Related Components." ML031130440. Washington, DC: U.S. Nuclear Regulatory Commission. August 8, 1988.

_____. NRC Information Notice 87-28, "Air Systems Problems at U.S. Light Water Reactors." Supplement 1. ML031130670. Washington, DC: U.S. Nuclear Regulatory Commission. December 28, 1987.

_____. NRC Information Notice 87-28, “Air Systems Problems at U.S. Light Water Reactors.” ML031130569. Washington, DC: U.S. Nuclear Regulatory Commission. June 22, 1987.

_____. NRC Information Notice 81-38, “Potentially Significant Components Failures Resulting from Contamination of Air-Operated Systems.” ML 8107230040. Washington, DC: U.S. Nuclear Regulatory Commission. December 17, 1981.

XI.M25 BOILING WATER REACTOR (BWR) REACTOR WATER CLEANUP SYSTEM

Program Description

This program is a condition monitoring program that provides inspections to manage the aging effects of cracking due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) on the intended function of certain austenitic stainless steel (SS) piping in the reactor water cleanup (RWCU) system of boiling water reactors (BWRs). Based on the U.S. Nuclear Regulatory Commission (NRC) criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG–0313, Revision 2, and NRC Generic Letter (GL) 88-01 and its Supplement 1.

NRC GL 88-01 applies to all BWR piping made of austenitic SS that is 4 inches or larger in nominal diameter and contains reactor coolant at a temperature above 93 °C [200 °F] during power operation, regardless of the American Society of Mechanical Engineers (ASME) Code classification. NRC GL 88-01 requests, in part, that affected licensees implement an inservice inspection (ISI) program conforming to staff positions for austenitic SS piping covered under the scope of the letter. In response to NRC GL 88-01, affected licensees undertook ISI in accordance with the scope and schedules described in the letter and included affected portions of RWCU piping outboard of the second isolation valves within their ISI programs.

The NRC issued GL 88-01, Supplement 1, to provide acceptable alternatives to the staff positions delineated in NRC GL 88-01. In NRC GL 88-01, Supplement 1, the staff noted, in part, that the position stated in NRC GL 88-01 on 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, provided that 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 the aging effects of 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 [200 °F] during power operation, regardless of ASME Code classification.

2. ***Preventive Actions****:* The comprehensive program outlined in NUREG–0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause SCC or IGSCC. These elements are a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. The program delineated in NUREG–0313 and NRC GL 88-01 includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. The resistant materials are used for new and replacement components and include low-carbon grades of austenitic SS and weld metal, with a maximum carbon of 0.035 wt.% and a minimum ferrite of 7.5 percent in weld metal and CASS. Special processes are used for existing as well as new and replacement components. These processes include solution heat treatment, heat sink welding, induction heating, and mechanical stress improvement. Reactor coolant water chemistry is monitored and maintained in accordance with activities that meet the guidelines in the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M2, "Water Chemistry."

3. ***Parameters Monitored or Inspected****:* The aging management program (AMP) monitors SCC or IGSCC of austenitic SS piping by detecting and sizing cracks in accordance with the guidelines of NUREG–0313, NRC GL 88-01, and NRC GL 88-01, Supplement 1.

4. ***Detection of Aging Effects****:* The extent, method, and schedule of the inspections delineated in the NRC inspection criteria for RWCU piping and NRC GL 88-01 are designed to maintain structural integrity and to detect aging effects before the loss of intended function of austenitic SS piping and fittings. Guidelines for the inspection schedule, methods, personnel, and sample expansion are based on NRC GL 88-01 and GL 88-01, Supplement 1, and any applicable alternatives to these inspections that were subsequently approved by the NRC. These alternative inspections are implemented in accordance with the current licensing basis for the plant. Typically, if all of the GL 89-10 actions had not been satisfactorily completed, then one alternative inspection would include 10 percent of the welds every refueling outage. Another alternative inspection would typically include at least 2 percent of the welds or 2 welds every refueling outage, whichever sample is larger, if: (a) all of the GL 89-10 actions had been satisfactorily completed, (b) no IGSCC had been detected in RWCU piping welds inboard of the second containment isolation valves, and (c) 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. For example, IGSCC was detected at Peach Bottom on certain welds inboard of primary containment isolation valves. Thus, the weld inspection sample size was reduced from 10 percent of the susceptible welds to 2 percent of the susceptible welds, as discussed in the letter from Joseph W. Shea, NRC, to George A. Hunger, Jr., PECO Energy Company, RWCU System Weld Inspections at Peach Bottom Atomic Power Station, Units 2 and 3.

5. ***Monitoring and Trending****:* The extent 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

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

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

10. ***Operating Experience****:* IGSCC has occurred in small- and large-diameter BWR piping made of austenitic SS. The comprehensive program outlined in NRC GL 88-01 and NUREG–0313 addresses improvements in all elements that cause SCC or IGSCC (e.g., susceptible material, significant tensile stress, and an aggressive environment) and is effective in managing IGSCC in austenitic SS piping in the RWCU system.

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.[1]

Letter from Robert M. Pulsifer, U.S. Nuclear Regulatory Commission, to Michael A Balduzzi, Vermont Yankee Nuclear Power Corporation, “Review of Request to Discontinue Intergranular Stress Corrosion Cracking Inspection of RWCU Piping Welds Outboard of the Second Containment Isolation Valves (TAC No. MB0468).” ML010780094. March 27, 2001.

Letter from Joseph W. Shea, U.S. Nuclear Regulatory Commission, to George A. Hunger, Jr., PECO Energy Company, “Reactor Water Cleanup (RWCU) System Weld Inspections at Peach Bottom Atomic Power Station, Units 2 and 3 (TAC Nos. M92442 and M92443).” ML090930466. September 15, 1995.

NRC. NRC Generic Letter 89-10, “Safety-related Motor Operated Valve Testing and Surveillance.” ML031150307. Washington, DC: U.S. Nuclear Regulatory Commission. August 3, 1990.

_____. NRC Generic Letter 88-01, “NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping.” Supplement 1. ML031130421. Washington, DC: U.S. Nuclear Regulatory Commission. February 4, 1992.

_____. NRC Generic Letter 88-01, “NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping.” ML031150675. Washington, DC: U.S. Nuclear Regulatory Commission. January 27, 1988.

_____. NUREG–0313, “Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping.” Rev. 2. ML031470422. Washington, DC: U.S. Nuclear Regulatory Commission. January 31, 1988.

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

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 ensure that their operability is maintained. The AMP also includes periodic inspection and testing of the halon/carbon dioxide (CO_2) fire suppression system. Additionally, this AMP is complemented by GALL-SLR Report AMP XI.S6 “Structures Monitoring” which consists of periodic visual inspections by personnel qualified to monitor structures and components (SCs) for applicable aging effects.

In accordance with 10 CFR 50.48(a), each operating nuclear power plant (NPP) licensee must have a fire protection plan that satisfies GDC 3, “Fire protection,” of Appendix A, “General Design Criteria for Nuclear Power Plants,” to 10 CFR Part 50, “Domestic Licensing of Production and Utilization Facilities.”

Licensees of plants that were licensed to operate before January 1, 1979, must meet the requirements of Appendix R, “Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979,” to 10 CFR Part 50, except to the extent provided for in 10 CFR 50.48(b). Licensees of plants licensed to operate after January 1, 1979, must meet the plant-specific fire protection licensing basis. Regulatory Guide (RG) 1.189 “Fire Protection for Nuclear Power Plants,” provides guidance for compliance with 10 CFR 50.48(b) and plant-specific fire protection licensing basis.

As an alternative to 10 CFR 50.48(b) or to 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” 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, Rick-Informed, Performance-Based Fire Protection for Existing Light-Water Nuclear Power Plants,” provides guidance for compliance with 10 CFR 50.48(c).

The deterministic means for meeting these requirements come from 10 CFR Part 50, Appendix R, and 10 CFR 50.48 or from plant-specific requirements incorporated into 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.

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., flamastic, 3M fire wrapping, 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 fire suppression system.

2. ***Preventive Actions****:* This is a condition monitoring program. However, the fire hazard analysis assesses the fire potential and fire hazard in all plant areas. It also specifies measures for fire prevention, fire detection, fire suppression, and fire containment and

alternative shutdown capability for each fire area containing structures, systems, and components important to safety.

3. ***Parameters Monitored or Inspected**:* Visual inspection of penetration seals examines the surface condition of the seals for any sign of degradation. Visual inspection of the surface condition of the fire barrier walls, ceilings, and floors and other fire barrier materials detects any sign of degradation. 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 fire suppression system are performed.

4. ***Detection of Aging Effects**:* Visual inspection of penetration seals detects cracking, seal separation from walls 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 every refueling outage. Visual inspection by fire protection qualified personnel of the fire barrier walls, ceilings, floors, and doors; fire damper housings; and other fire barrier materials performed in walkdowns at a frequency in accordance with an NRC-approved fire protection program ensure timely detection of cracking, spalling, and loss of material. Visual inspection by fire protection qualified personnel detects any sign of degradation of the fire doors, such as wear and missing parts. Periodic visual inspection and function tests detect degradation of the fire doors before there is a loss of intended function.

   Visual inspections of the halon/CO_2 fire suppression system are performed to detect any sign of corrosion before the loss of the component intended function.

5. ***Monitoring and Trending**:* The results of inspections of the aging effects of cracking, spalling, and loss of material on fire barrier penetration seals, fire barriers, fire dampers, and fire doors are trended to provide for timely detection of aging effects so that the appropriate corrective actions can be taken.

6. ***Acceptance Criteria**:* Inspection results are acceptable if there are no signs of degradation that could result in the loss of the fire protection capability due to loss of material. The acceptance criteria include (a) no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals; (b) no significant indications cracking, spalling, 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 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the

Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related 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, 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.

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

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

10. ***Operating Experience**:* Silicone foam fire barrier penetration seals have experienced splits, shrinkage, voids, lack of fill, and other failure modes [NRC Information Notice (IN) 88-56, IN 94-28, and IN 97-70]. Degradation of electrical raceway fire barrier such as small holes, cracking, and unfilled seals are found on routine walkdown (NRC IN 91-47 and NRC Generic Letter 92-08). Fire doors have experienced wear of the hinges and handles.

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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. 2015.

10 CFR 50.48, "Fire Protection." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

NFPA. NFPA 805, *Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants*. National Fire Protection Association. 2001.

NRC. NRC Regulatory Guide 1.205, “Risk-Informed, Performance-Based Fire Protection for Existing Light-Water Nuclear Power Plants.” Revision 1. ML092730314. Washington, DC: U.S. Nuclear Regulatory Commission. December 31, 2009.

_____. NRC Regulatory Guide 1.189, “Fire Protection for Nuclear Power Plants.” Revision 2. ML092580550. Washington, DC: U.S. Nuclear Regulatory Commission. October 27, 2009.

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

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

_____. NRC Generic Letter 92-08, “Thermo-Lag 330-1 Fire Barrier.” ML031130425. Washington, DC: U.S. Nuclear Regulatory Commission. December 17, 1992.

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

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 due to general, pitting, and crevice corrosion, microbiologically-induced corrosion or fouling, and flow blockage due to fouling is adequately managed. In addition to NFPA codes and standards, portions of the water-based fire protection system that are: (a) normally dry but periodically are subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect, are subjected to augmented testing or inspections. Also, portions of the system (e.g., fire service main, standpipe) are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions are initiated.

Either sprinklers are replaced before reaching 50 years inservice or a representative sample of sprinklers from one or more sample areas is tested by using the guidance of the 2011 Edition of NFPA 25, “Inspection, Testing and Maintenance of Water-Based Fire Protection Systems” to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report AMP XI.M41, “Buried and Underground Piping and Tanks,” is used to monitor the external surfaces of buried and underground water-based fire protection system piping and tanks.

Evaluation and Technical Basis

1. ***Scope of Program**:* Components within the scope of water-based fire protection systems include items such as sprinklers, nozzles, fittings, valve bodies, fire pump casings, hydrants, hose stations, fire water storage tanks, fire service mains, and standpipes. The internal surfaces of water-based fire protection system piping that is normally drained, such as dry-pipe sprinkler system piping, are included within the scope of the AMP. Fire hose stations and standpipes are considered piping in the AMP. Fire hoses and gaskets can be excluded from the scope of license renewal if the standards that are relied upon to prescribe replacement of the hose and gaskets are identified in the scoping methodology description.

2. ***Preventive Actions**:* Flushes (e.g., NFPA 25 Section 7.3.2.1) mitigate or prevent fouling, which can cause flow blockage or loss of material, by clearing corrosion products and sediment.

3. ***Parameters Monitored or Inspected**:* Loss of material could reduce wall thickness of the fire protection piping system components and 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 corrosion conditions. Periodic flow tests, flushes, and internal and external visual inspections are performed to ensure that the system maintains its intended function. Testing of sprinklers ensures that degradation is detected in a timely manner. 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.

4. ***Detection of Aging Effects**:* Water-based fire protection system components are subject to flow testing (except for fire water storage tanks), other testing, and visual inspections. Testing and visual inspections are performed in accordance with Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations."

   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: (a) the condition of the external surfaces of components, (b) the conditions of the internal surfaces of components that could indicate wall loss, and (c) 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 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, follow-up volumetric examinations are performed. When fouling is identified, deposits are removed to determine if loss of material has occurred and to prevent further degradation in the system.

   c. Visual inspection of yard fire hydrants ensures timely detection of signs of degradation, such as corrosion. Fire hydrant hose hydrostatic tests, gasket inspections, and fire hydrant flow tests ensure that fire hydrants can perform their intended function and 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:

   - 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-induced corrosion). 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 towards 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 the 2011 Edition of NFPA 25.

If the environmental (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. If not, additional inspection activities are needed to ensure that the intended function of buried and underground fire protection piping is maintained consistent with the current licensing basis (CLB) for the subsequent period of extended operation.

The water-based fire protection systems are normally maintained at required operating pressure and monitored in such a way that loss of system pressure is immediately detected and corrected when acceptance criteria are exceeded. Continuous system pressure monitoring or equivalent methods (e.g., number of jockey fire pump starts or run time) are conducted.

Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Noncode 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.

Aging effects associated with fire water system components having only CLB intended functions of leakage boundary (spatial) or structural integrity (attached) as defined in Standard Review Plan for Subsequent License Renewal (SRP-SLR) Table 2.1-4(b) may be managed by 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[1, 2, 5]	
Description	**NFPA 25 Section**
Sprinkler Systems	
Sprinkler inspections[5]	5.2.1.1
Sprinkler testing[7]	5.3.1
Standpipe and Hose Systems	
Flow tests	6.3.1
Private Fire Service Mains	
Underground and exposed piping flow tests	7.3.1
Hydrants	7.3.2
Fire Pumps	
Suction screens	8.3.3.7
Water Storage Tanks	
Exterior inspections	9.2.5.5
Interior inspections	9.2.6[4], 9.2.7
Valves and System-Wide Testing	
Main drain test	13.2.5
Deluge valves[8]	13.4.3.2.2 through 13.4.3.2.5
Water Spray Fixed Systems	
Strainers (after each system actuation)	10.2.1.6, 10.2.1.7, 10.2.7
Operation test (refueling outage interval)	10.3.4.3
Foam Water Sprinkler Systems	
Strainers (refueling outage interval and after each system actuation)	11.2.7.1
Operational Test Discharge Patterns (annually)[6]	11.3.2.6
Storage tanks (internal–10 years)	Visual inspection for internal corrosion
Obstruction Investigation	
Obstruction, internal inspection of piping[3]	14.2 and 14.3

1. All terms and references are to the 2011 Edition of NFPA 25. The staff cites the 2011 Edition of NFPA 25 for the description of the scope and periodicity of specific inspections and tests. This table specifies those inspections and tests that are related to age-managing applicable aging effects associated with loss of material and flow blockage for passive long-lived in-scope components in the fire water system. Inspections and tests not related to the above continue to be conducted in accordance with the plant's CLB. If the CLB specifies more frequent inspections than required by NFPA 25 or this table, the plant's CLB continues to be met.
2. A reference to a section includes all subbullets unless otherwise noted. Section 5.2.1.1 includes Sections 5.2.1.1.1 through 5.2.1.1.7.
3. The alternative nondestructive examination methods permitted by Sections 14.2.1.1 and 14.3.2.3 are limited to those that can ensure that flow blockage will not occur.
4. In regard to Sections 9.2.6.4 and 9.2.7: When degraded coatings are detected, the acceptance criteria and corrective action recommendations in GALL-SLR Report AMP XI.M42 are followed in lieu of 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 Section 9.2.7 (3) in the vicinity of the loss of material. Vacuum box testing as stated in Section 9.2.7 (6) is conducted when pitting, cracks, or loss of material is detected in the immediate vicinity of welds. Bottom-thickness measurements are taken on each tank in the 10-year period before a subsequent period of extended operation unless condition-based bottom thickness measurements have been obtained as described in Section 9.2.7 (5) in the same time period.
5. 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 every refueling outage interval.
6. 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.
7. 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 including the sample size, sample selection criteria, and minimum time in service of tested sprinklers; or
    - Proposes to test the sprinklers in accordance with NFPA 25 Section 5.3.1.1.2.
8. If past testing results demonstrate that sufficient nozzles are not obstructed such that full design flow could be achieved, the test frequency does not exceed 3 years. Otherwise, tests are conducted annually except 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.

5. ***Monitoring and Trending****:* Visual inspection results are monitored and evaluated. System discharge pressure or equivalent methods (e.g., number of jockey fire pump starts or run time) are monitored continuously and evaluated. Results of flow testing (e.g., buried and underground piping, fire mains, and sprinkler), flushes, and wall thickness measurements are monitored and trended. Degradation identified by flow testing, flushes, and inspections is evaluated. Rates of degradation are trended in order to confirm that the timing of the next inspection will occur before a loss of intended function of an in-scope component.

6. ***Acceptance Criteria****:* The acceptance criteria are: (a) the water-based fire protection system is able to maintain required pressure and flow rates, (b) minimum design wall thickness is maintained, and (c) no fouling exists in the sprinkler systems that could cause corrosion or flow blockage in the sprinklers.

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

   If the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material is removed and its source is determined and corrected.

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

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

10. ***Operating Experience****:* Operating experience (OE) shows that water-based fire protection systems are subject to loss of material due to corrosion, microbiologically-induced corrosion, 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 operating experience 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.

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.

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.

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 3.2.2.2.8, 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

NFPA. NFPA 25, *Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems.* National Fire Protection Association. 2011.

NRC. NRC Information Notice 2013-06, "Corrosion in Fire Protection Piping Due to Air and Water Interaction." ADAMS Accession No. ML13031A618. Washington, DC: U.S. Nuclear Regulatory Commission. March 25, 2013.

XI.M29 ABOVEGROUND METALLIC TANKS

Program Description

The Aboveground Metallic Tanks aging management program (AMP) manages the effects of loss of material and cracking on the outside and inside surfaces of aboveground tanks constructed on concrete or soil. All outdoor tanks (except fire water storage tanks) and certain indoor tanks are included. If the tank exterior is fully visible, the tank's 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 a preventive measure to mitigate corrosion. The program relies on periodic inspections to monitor 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, corrosion could occur at inaccessible locations, such as the tank bottom. Accordingly, verification of the effectiveness of the program is performed to ensure that significant degradation in inaccessible locations is not occurring and that the component's intended function is maintained during the subsequent period of extended operation. For reasons set forth below, an acceptable verification program consists of thickness measurements of the tank bottom.

Evaluation and Technical Basis

1. ***Scope of Program**:* Tanks within the scope of this program include all outdoor tanks except the fire water storage tank, constructed on soil or concrete. Indoor large volume 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 are also included. If the tank exterior is fully visible, 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 tanks are managed using GALL-SLR Report AMP XI.M27. Visual inspections are conducted on tank insulation and jacketing when these are installed.

   This program may be used to manage the aging effects for 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 Generic Aging Lessons Learned (GALL) Report AMP XI.M42 are incorporated into this AMP.

   - Exceptions or enhancements associated with the recommendations in GALL Report AMP XI.M42 are included in this AMP.

   - The Final Safety Analysis Report (FSAR) supplement for GALL Report AMP XI.M42, as shown in SRP-SLR Table 3.0-1, "FSAR Supplement for Aging Management of Applicable Systems," 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 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., 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 degradation of coatings, sealants, and caulking because it is a condition directly related to the potential loss of material. Thickness measurements of the bottoms of the tanks are made periodically for the tanks monitored by this program as an additional way to ensure that loss of material is not occurring at locations inaccessible for inspection. 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., 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, an inspection of the coating is performed to ensure that the surface is protected from moisture. Periodic visual inspections at each outage are conducted to confirm that the paint, coating, sealant, and caulking are intact. The visual inspections of sealant and caulking are supplemented with 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 (SS), 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.

Table XI.M29-1. Tank Inspection Recommendations[1, 2]

Material	Environment	Aging Effect Required Aging Management (AERM)	Inspection Technique[3]	Inspection Frequency
Inspections to Identify Degradation of Inside Surfaces of Tank Shell, Roof[4], and Bottom[5, 6]				
Steel	Raw water Waste water	Loss of material	Visual from inside surface (IS) or Volumetric from outside surface (OS)[7]	Each 10-year period starting 10 years before the subsequent period of extended operation
Steel	Treated water	Loss of material	Visual from inside surface (IS) or Volumetric from outside surface (OS)[7]	One-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32[8]
Stainless steel[8, 14]	Treated water	Loss of Material	Visual from IS or Volumetric from OS[7]	One-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32[8] or periodic inspections see SRP-SLR Sections 3.2.2.2.12, 3.3.2.2.12, or 3.4.2.2.9.
Aluminum	Treated water	Loss of Material	Visual from IS or Volumetric from OS[7]	One-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32[8]
Inspections to Identify Degradation of External Surfaces[9] of Tank Shell, Roof, and Bottom				
Material	**Environment**	**AERM**	**Inspection Technique[3]**	**Inspection Frequency**
Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Visual from OS	Each refueling outage interval
Steel	Soil or concrete	Loss of material	Volumetric from IS[12]	Each 10-year period starting 10 years before the subsequent period of extended operation[13]
Stainless steel[14]	Any indoor air environment	Cracking	Surface [10, 11]	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 3.2.2.2.5, 3.3.2.2.3, or 3.4.2.2.2.
Stainless steel[14]	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval or demonstrate that loss of material is not an applicable aging effect, see SRP-SLR Sections 3.2.2.2.2, 3.3.2.2.4, or 3.4.2.2.3.
Stainless steel[14]	Air-outdoor	Cracking	Surface[10, 11]	Each 10-year period starting 10 years before the subsequent period of extended operation or demonstrate that SCC is not an applicable aging effect,

Table XI.M29-1. Tank Inspection Recommendations[1, 2]

				see SRP-SLR Sections 3.2.2.2.5, 3.3.2.2.3, or 3.4.2.2.2.
	Soil or concrete	Loss of material	Volumetric from IS[12]	Each 10-year period starting 10 years before the subsequent period of extended operation[13]
Aluminum	Any indoor air environment	Cracking	Surface[10, 11]	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 3.2.2.2.10, 3.3.2.2.10, or 3.4.2.2.7.
	Any air environment	Loss of material	Visual from OS	One-time inspection conducted in accordance with AMP XI.M32 or demonstrate that loss of material is not an applicable aging effect, see SRP-SLR Sections 3.2.2.2.13, 3.3.2.2.13, or 3.4.2.2.10.
	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
		Cracking[14]	Surface[10, 11]	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 3.2.2.2.10, 3.3.2.2.10, or 3.4.2.2.7.
	Soil or concrete	Loss of Material	Volumetric from IS[12]	Each 10-year period starting 10 years before the subsequent period of extended operation[13]

1. 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, inspections to identify aging of the external surfaces of tank bottoms and tank shells exposed to soil or concrete 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.
2. 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.
3. 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 AERM and a sufficient amount of the surface is inspected to ensure that localized aging effects are detected. For example, in some cases, subject to being demonstrated effective by the applicant, the low frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. If followup ultrasonic examinations are conducted in any areas where the wall thickness is below nominal, an LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom.
4. 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.
5. 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 SLRA includes a justification for how aging effects will be detected before the loss of the tank's intended function.
6. 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.

Table XI.M29-1. Tank Inspection Recommendations[1, 2]

7. At least 25 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 be demonstrated effective by the applicant.
8. At least one tank for each material and environment combination is inspected at each site. The tank inspection can be credited towards the sample population for GALL-SLR Report AMP XI.M32.
9. 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.
10. 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 the absence of environmental impacts in the vicinity of the plant due to: (a) the plant being located within approximately 5 miles of a saltwater coastline, or within 1/2 mile of a highway that is treated with salt in the wintertime, or in areas in which the soil contains more than trace amounts of chlorides, (b) cooling towers where the water is treated with chlorine or chlorine compounds, and (c) chloride contamination from other agricultural or industrial sources. The evaluation includes soil sampling in the vicinity of the tank (because soil results indicate atmospheric fallout accumulating in the soil and potentially affecting tank surfaces) and sampling of residue on the top and sides of the tank to ensure that chlorides or other deleterious compounds are not present at sufficient levels to cause pitting corrosion, crevice corrosion, or cracking.
11. 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 are examined. The sample inspection points are distributed in such a way that inspections occur in those areas most susceptible to degradation (e.g., areas where contaminants could collect, inlet and outlet nozzles, welds).
12. 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 13, below, or propose an alternative examination methodology.
13. 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 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.
14. If the tank contents are greater than 60 °C [140 °F] , or the tank's surface could be greater than 60 °C [140 °F] due to exposure to the environment (e.g., direct sunlight on the surfaces of the tank), stress corrosion cracking is an applicable aging effect and surface examinations are conducted to detect potential cracking. Reference footnote 11 for the extent of inspections.

If the exterior surface of an outdoor tank or indoor tank exposed to condensation (because 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.” At a minimum, during each 10 year period of the subsequent period of extended operation, a minimum of either 25 1 square foot sections or 20 percent of the surface area of insulation is removed to permit inspection of the exterior surface of the tank. 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, and

    ii. No evidence of stress corrosion cracking (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 (CUI) 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 towards the inspection quantities for other types of insulation.

Potential corrosion of tank bottoms is determined from ultrasonic testing (UT) thickness measurements of the tank bottoms that are taken whenever the tank is drained or at intervals not less than those recommended in Table XI.M29-1. Measurements are taken to ensure that significant degradation is not occurring and that the component's intended function is maintained during the period of extended operation.

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 (ASME) Code follow procedures consistent with the ASME code. Noncode 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 that ensure an adequate examination.

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, periodic inspections provide for timely detection of aging effects. The effects of corrosion on the inaccessible external surfaces are detectable by UT thickness measurements of the tank bottom and are monitored and trended if significant material loss is detected and successive measurements are available.

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. Non-pliable, 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. UT thickness measurements of the tank bottom are evaluated against the design thickness and corrosion allowance.

7. ***Corrective Actions****:* The site corrective actions program, quality assurance procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. As discussed in the Appendix for GALL, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls. Flaws in the caulking or sealant are repaired and followup examination of the tank's surfaces is conducted if deemed appropriate.

   Any loss of material; cracking; degradation of paints or coatings (e.g., cracking, flaking, or peeling); or drying, cracking, or missing sealant and caulking is evaluated to determine whether the degradation could impact the tank's intended function prior to the next scheduled inspection.

8. ***Confirmation Process****:* The confirmation process is addressed through those specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the

confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

10. ***Operating Experience**:* A review of operating experience (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 Standard Review Plan-Subsequent License Renewal (SRP-SLR) 3.2.2.2.8, 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

NRC. NRC Information Notice 2013-18, “Refueling Water Storage Tank Degradation.” ML13128A118. Washington, DC: U.S. Nuclear Regulatory Commission. September 13, 2013.

XI.M30 FUEL OIL CHEMISTRY

Program Description

The program includes (a) surveillance and maintenance procedures to mitigate corrosion and (b) 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 0975-04, D 1796-97, D 2276-00, D 2709-96, D 6217-98, and D 4057-95, 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 ensure that significant degradation is not occurring and that the component's intended function is maintained during the subsequent period of extended operation. Thickness measurement of the tank bottom is an acceptable verification program.

The fuel oil chemistry program is generally effective in removing impurities from areas that experience flow. The GALL-SLR Report identifies those circumstances in which the fuel oil chemistry program is to be augmented to manage the effects of aging for subsequent license renewal (SLR). For example, the fuel oil chemistry program may not be effective in stagnant areas. Accordingly, in certain cases as identified in this GALL-SLR Report, verification of the effectiveness of the fuel oil chemistry program is undertaken to ensure that significant degradation is not occurring and that the component's intended function is maintained during the subsequent period of extended operation. As discussed in this GALL-SLR Report for these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system.

Evaluation and Technical Basis

1. ***Scope of Program****:* Components within the scope of the program are the diesel fuel oil storage tanks, piping, and other metal components subject to aging management review that are exposed to an environment of diesel fuel oil. The program is focused on managing loss of material due to general, pitting, and crevice corrosion, microbiologically-induced corrosion, and fouling that leads to corrosion of the diesel fuel tank internal surfaces.

2. ***Preventive Actions****:* The program reduces the potential for (a) exposure of the storage tanks' internal surface 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 (b) 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 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 the tank 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, microbiologically-induced corrosion, and fouling that leads to corrosion of the diesel fuel tank 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 ensure that loss of material is not occurring.

4. ***Detection of Aging Effects**:* Loss of material due to corrosion of the diesel fuel oil tank or other components exposed to diesel fuel oil cannot occur without exposure of the tank's internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Periodic multilevel sampling provides assurance that fuel oil contaminants are below unacceptable levels. If tank design features do not allow for multilevel sampling, a sampling methodology that includes a representative sample from the lowest point in the tank may be used.

   At least once during the 10-year period prior to the subsequent period of extended operation, each diesel fuel tank is drained and cleaned, the internal surfaces are visually inspected (if physically possible) and volumetrically-inspected if evidence of degradation is observed during visual inspection, or if visual inspection is not possible. During the subsequent period of extended operation, at least once every 10 years, each diesel fuel tank is drained and cleaned, the internal surfaces are visually inspected (if physically possible), and, if evidence of degradation is observed during inspections, or if visual inspection is not possible, these diesel fuel tanks are volumetrically inspected.

   Prior to the subsequent period of extended operation, a one-time inspection (i.e., GALL-SLR Report AMP XI.M32) of selected components exposed to diesel fuel oil is performed to verify the effectiveness of the Fuel Oil Chemistry program.

5. ***Monitoring and Trending**:* Water, biological activity, and particulate contamination concentrations are monitored and trended in accordance with the plant's technical specifications or at least quarterly. In addition, the inspection results are trended and the inspection periodicity is shortened when available evidence, including trending, indicates the acceptance criteria may be exceeded before the next scheduled inspection.

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 0975-04 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   Corrective actions are taken 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 corrosion, a biocide is added to fuel oil.

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

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

10. ***Operating Experience**:* The operating experience 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 American Petroleum Institute (API) 653 standard by welding patch plates over the affected area.

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

ASTM. ASTM D 0975-04, “Standard Specification for Diesel Fuel Oils.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 2004.

_____. ASTM D 4057-95, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 2000.

_____. ASTM D 2276-00, “Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 2000.

_____. ASTM D 6217-98, “Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 1998.

_____. ASTM D 1796-97, “Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 1997.

_____. ASTM D 2709-96, “Standard Test Method for Water and Sediment in Middle Distillate Fuels by Centrifuge.” West Conshohocken, Pennsylvania: American Society for Testing Materials. 1996.

NRC. “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.” ML091660470. Washington, DC: U.S. Nuclear Regulatory Commission. June 30, 2009.

_____. NRC Regulatory Guide 1.137, “Fuel-Oil Systems for Standby Diesel Generators.” Revision 1. ML003740180. Washington, DC: U.S. Nuclear Regulatory Commission, October 31, 1979.

XI.M31 REACTOR VESSEL MATERIAL SURVEILLANCE

Program Description

Appendix H of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix H requires implementation of a reactor vessel material surveillance program to monitor the changes in fracture toughness to 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 >1MeV]. 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.

The surveillance program must comply with ASTM International (formerly American Society for Testing and Materials) Standard Practice E 185-82, as incorporated by reference in 10 CFR Part 50, Appendix H. Because the withdrawal schedule in Table 1 of ASTM E 185-82 is based on plant operation during the original 40-year license term, standby capsules may need to be incorporated into the Appendix H program to ensure 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 one and one quarter (1.25) times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation.

As an alternative to a plant-specific surveillance program complying with ASTM E 185-82, an integrated surveillance program (ISP) may be considered for a set of reactors that have similar design and operating features, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.C. The plant-specific implementation of the ISP is consistent with the latest version of the ISP plan that has received approval by the 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 (a) monitor irradiation embrittlement to neutron fluence greater than the projected fluence at the end of the subsequent period of extended operation, and (b) 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.

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 time-limited aging analysis (TLAAs) described in Section 4.2 of the

Standard Review Plan for Subsequent License Renewal (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 (RV) components and reactor vessel internal (RVI) components.

In accordance with 10 CFR Part 50, 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 to the capsule withdrawal schedule, including the conversion of standby capsules into the Appendix H program and extension of the surveillance program for the subsequent period of extended operation, must be approved by the NRC prior to 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.

Evaluation and Technical Basis

The Reactor Vessel Material Surveillance program is plant-specific and depends on the composition and availability of the limiting materials, the availability of surveillance capsules, and the projected neutron fluence at the end of the subsequent period of extended operation. In accordance with 10 CFR Part 50, Appendix H, an applicant submits its proposed withdrawal schedule for NRC approval prior to implementation.

1. ***Scope of Program****:* The program addresses neutron embrittlement of all reactor vessel beltline materials as defined by 10 CFR Part 50, Appendix G as the region of the reactor vessel that directly surrounds the effective height of the active core and the adjacent regions of the reactor vessel that are predicted to experience sufficient neutron damage to be considered in the selection of the limiting material with regard to radiation damage. Materials with a projected neutron fluence greater than 10^{17} n/cm^2 (E >1MeV) at the end of the license are considered to experience sufficient neutron damage to be included in the beltline. Materials originally monitored within the licensee’s existing 10 CFR Part 50, Appendix H, materials surveillance program will continue to serve as the basis for the reactor vessel surveillance aging management program (AMP) unless safety considerations for the term of the subsequent period of extended operation would require the monitoring of additional or alternative materials.

   For integrated surveillance programs (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 received approval 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 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 long term operating conditions of the reactor vessel (i.e., vessel beltline operating temperature and neutron fluence) that could affect neutron irradiation embrittlement of the reactor vessel.

The program uses two parameters to monitor the effects of neutron irradiation: (a) the increase in the Charpy V-notch 30 ft-lb transition temperature and (b) the drop in the Charpy V-notch USE. The program uses neutron dosimeters to benchmark 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 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 one and one quarter (1.25) times the projected peak vessel neutron fluence subsequent period of extended operation. Test results are required to be reported consistent with the requirements of 10 CFR Part 50, Appendix H.

Because the degree of neutron irradiation embrittlement is a function of the neutron fluence, calculations of the capsule fluence and the reactor vessel wall fluence are important parts of the program. The methods used to determine both capsule and reactor vessel wall fluence values are consistent with Regulatory Guide (RG) 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” as described in 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 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 in accordance with the requirements of 10 CFR Part 50, Appendix H. The ASTM standards referenced in Appendix H describe the methods used to monitor irradiation embrittlement (as described in Element 3, above), selection of materials, and the withdrawal schedule for capsules. Because the withdrawal schedule in Table 1 of ASTM E185-82 is based on plant operation during the original 40-year license term, standby capsules may need to be converted to testing program capsules within a withdrawal schedule that covers the subsequent period of extended operation.

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 in accordance with 10 CFR Part 50, Appendix H, Paragraph III.C. For an ISP, in some cases the plant Reactor Vessel Material Surveillance Program may result in no surveillance capsules being irradiated in the plant’s reactor vessel, with the plant relying on data from testing of the ISP capsules from 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 that has received approval by the NRC for the subsequent period of extended operation.

If all surveillance capsules have been removed and tested, a plant may seek membership in an ISP. In addition, the plant institutes a supplemental neutron monitoring program, to meet the requirement of 10 CFR Part 50, Appendix H, III.C.1.b, that each reactor in an ISP has an adequate dosimetry program. Alternatively, this program can propose implementation of in-vessel irradiation of capsule (s) with reconstituted specimens from previously tested capsules and appropriate and neutron monitoring.

If no invessel surveillance capsules are available, an alternative neutron monitoring program uses alternative dosimetry, either from invessel dosimetry capsules or ex-vessel capsules, to monitor neutron fluence during the subsequent period of extended operation. The methods used in this alternative neutron monitoring program are consistent with RG 1.190, including appropriate benchmarking, as described in AMP X.M2, "Neutron Fluence Monitoring."

If all surveillance capsules have been removed and tested, operating restrictions are established to ensure that the plant is operated under conditions that are consistent with and bounded by those to which the surveillance capsules were exposed. The exposure conditions of the reactor vessel are monitored to ensure that they are consistent with the operating restrictions. 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, if deemed 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 implementation.

5. ***Monitoring and Trending****:* The program provides data on neutron embrittlement of the reactor vessel materials and neutron fluence data. These data are to evaluate the TLAAs on neutron irradiation embrittlement [e.g., USE, pressurized thermal shock (PTS) and pressure-temperature limits evaluations, etc.] as needed to demonstrate compliance with the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.61 or 10 CFR 50.61a for the licensed operating period of the plant. The applicable TLAAs are described in subsequent license renewal applications (SLRA) Section 4.2 (see SRP-SLR Section 4.2).

The plant-specific surveillance program or ISP has at least one capsule that will attain projected neutron fluence equal to or exceeding the peak reactor vessel wall neutron fluence at the end of the subsequent period of extended operation. The program withdraws and tests the capsule(s) at an outage in which the capsule receives a neutron fluence of between one and one and one quarter (1.25) times the peak reactor vessel wall neutron fluence projected at the end of the subsequent period of extended operation. Test results from this capsule are reported in accordance with 10 CFR Part 50, Appendix H. If an existing standby capsule that has been previously withdrawn from the reactor vessel is used for testing 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 governed by 10 CFR Part 50, Appendix H.

The surveillance program retains additional capsules within the reactor vessel to support additional testing if, for example, the data from the required surveillance capsule turn out to be invalid, or to provide contingencies for future use. If the projected neutron fluence for these additional capsules is expected to be excessive when left in the reactor vessel, the program may propose to withdraw and place one or more untested capsules in storage for future reinsertion and/or testing.

If a plant has ample capsules remaining for future use, all pulled and tested samples placed in storage with reactor vessel neutron fluence less than 50 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 50 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 saved for 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 ample capsules remaining for future use, all pulled and tested capsules 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 removed 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.

Evaluations of the neutron embrittlement of the reactor vessel materials are based on the specific results of the surveillance program or from correlations that utilize the material chemistry and the vessel neutron fluence. These evaluation are in accordance with NRC RG 1.99, Rev. 2, “Radiation Embrittlement of Reactor Vessel Materials,” or the PTS rules (10 CFR 50.61 or 10 CFR 50.61a), as appropriate, and as governed by those documents.

If the program determines embrittlement using surveillance data, then the applicable bounds of the data, such as cold leg operating temperature and neutron fluence, are used to establish operating restrictions for the plant. If the plant uses an embrittlement trend curve to determine embrittlement (such as those of RG 1.99, Rev. 2, 10 CFR 50.61, and 10 CFR 50.61a), the program ensures that the operating conditions for the reactor vessel beltline are within the applicability limits of the embrittlement trend curve with respect to parameters such as irradiation temperature, neutron fluence, and flux, or provides technical justification for exceeding these applicability limits.

6. ***Acceptance Criteria****:* Although there are no specific acceptance criteria that apply to the surveillance data themselves, the program provides compliance with 10 CFR Part 50, Appendix H, and 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 acceptability of other plant-specific analyses, throughout the subsequent period of extended operation.

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

   Since the data from this program are used for reactor vessel embrittlement projections to comply with regulations (e.g., 10 CFR Part 50, Appendix G, requirements, and 10 CFR 50.61 or 10 CFR 50.61a limits) through the subsequent period of extended operation, corrective actions would be necessary if these requirements are not satisfied, or if this program fails to comply with Appendix H of 10 CFR Part 50. If plant operating characteristics exceed the operating restrictions identified previously, such as a lower reactor vessel operating temperature or a higher fluence, this program provides 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 those specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

10. ***Operating Experience**:* The existing reactor vessel material surveillance program provides sufficient material data and dosimetry to (a) monitor irradiation embrittlement at the end of the subsequent period of extended operation and (b) determine the need for operating restrictions on the inlet temperature, neutron fluence, and neutron flux.

    This program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR Part 50, Appendix G, "Fracture Toughness Requirements." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR Part 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2010.

10 CFR 50.61a, “Alternate Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2010.

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.

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.

NRC. NRC Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” ML010890301. Washington, DC: U.S. Nuclear Regulatory Commission. March 31, 2001.

_____. NRC Regulatory Guide 1.99, “Radiation Embrittlement of Reactor Vessel Materials.” Rev. 2. ML003740284. Washington, DC: U.S. Nuclear Regulatory Commission. May 31, 1988.

XI.M32 ONE-TIME INSPECTION

Program Description

A one-time inspection of selected components is conducted just prior to the beginning of a subsequent period of extended operation (e.g., prior to the second period of extended operation) in order to verify the system-wide effectiveness of an aging management program (AMP) that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the subsequent period of extended operation. For example, effective control of water chemistry under the XI.M2, “Water Chemistry,” program can prevent some aging effects and minimize others. However, there may be locations that are isolated from the flow stream for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. This program provides inspections that verify that unacceptable degradation is not occurring. It also may trigger additional actions that ensure the intended functions of affected components are maintained during subsequent 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: (a) an aging effect is not expected to occur, but the data are insufficient to rule it out with reasonable confidence; or (b) 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 prior operating experience data.

In addition, for steel components exposed to water environments that do not include corrosion inhibitors as a preventive action (i.e., treated water, reactor coolant, raw water, or 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 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: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environments, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the subsequent period of extended operation.

The program may include a review of routine maintenance, repair, or inspection records to confirm that selected components have been inspected for aging degradation within the recommended time period for the inspections related to the subsequent period of extended operation, and that significant aging degradation has not occurred. A one-time inspection program is acceptable to verify the effectiveness of GALL-SLR Report AMP XI.M2, “Water Chemistry,” GALL-SLR Report AMP XI.M30, “Fuel Oil Chemistry,” and GALL-SLR Report AMP XI.M39, “Lubricating Oil Analysis,” where the environment in the subsequent period of extended operation is expected to be equivalent to that in the prior operating period and for which no aging effects have been observed. However, the one-time inspection for environments that do not fall in the above category, or of any other action or program created to verify the effectiveness of an AMP and confirm the absence of an aging effect, is to be reviewed by the staff on a plant-specific basis.

This program cannot be used for structures or components with known age-related degradation mechanisms or when the environment in the subsequent period of extended operation is not expected to be equivalent to that in the prior operating period. Periodic inspections are proposed in these cases.

Evaluation and Technical Basis

1. ***Scope of Program**:* The scope of this program includes systems and components that are subject to aging management using GALL-SLR Report AMPs XI.M2, "Water Chemistry;" XI.M30, "Fuel Oil Chemistry;" and XI.M39, "Lubricating Oil Analysis;" and for which no aging effects have been observed or for which the aging effect is occurring very slowly and will not affect the component's or structure's intended function during the subsequent period of extended operation based on prior operating experience data. The scope of this program also may include other components and materials where the environment in the period of extended operation is expected to be equivalent to that in the prior operating period and for which no aging effects have been observed. The scope of this program includes managing long-term loss of material due to general corrosion for steel components. Long-term loss of material due to general corrosion for steel components need not be managed if two conditions are met: (i) the environment for the steel components includes corrosion inhibitors as a preventive action; and (ii) periodic wall thickness measurements on a representative sample of each environment have been conducted every 5 years up to at least the 50th year of operation. Environments such as treated water, reactor coolant, 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 operating experience for the prior operating period,

   - When the environment in the subsequent period of extended operation is not expected to be equivalent to that in the prior operating period, or

   - When aging effects that do not meet acceptance criteria are identified during the one-time inspection conducted in the prior operating period or during the review of plant-specific or industry operating experience.

   Periodic inspections are proposed in these cases.

2. ***Preventive Actions**:* One-time inspection is a condition monitoring program. It does not include methods to mitigate or prevent 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 effect are provided in the table in Element 4, below. Inspection is performed using a variety of nondestructive examination (NDE) methods, including visual, volumetric, and surface techniques.

4. ***Detection of Aging Effects**:* Elements of the program include (a) 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; (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; and (c) 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 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 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 cleaning processes that ensure an adequate examination. In addition, a description of enhanced visual examination (EVT)-1 is found in Boiling Water Reactor Vessel and Internals Project (BWRVIP)-03 and Materials Reliability Program (MRP)-228.

The inspection and test techniques have a demonstrated history of effectiveness in detecting the aging effect of concern. Typically, the one-time inspections are performed as indicated in the following table.

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.

[1] Refer to the GALL-SLR Report, Chapter I, for acceptable editions and addenda of the ASME Code, Section XI.

Table XI.M32-1. Examples of Parameters Monitored or Inspected and Aging Effect for Specific Structure or Component[1]

Aging Effect	Aging Mechanism	Parameter(s) Monitored	Inspection Method[2]
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-induced 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)
Loss of Material	Erosion	Surface Condition or Wall Thickness	Visual (e.g., VT-3) 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)

[1]The examples provided in the 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.
[2]Visual inspection may be used only when the inspection methodology examines the surface potentially experiencing the aging effect.

With respect to inspection timing, the sample of components inspected before the end of the current operating term needs to be sufficient to provide reasonable assurance that the aging effect will not compromise any intended function during the subsequent period of extended operation. Specifically, inspections need to be completed early enough to ensure that the aging effects that may affect intended functions early in the subsequent period of extended operation are appropriately managed. Conversely, inspections need to be timed to allow the inspected components to attain sufficient age to ensure 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.

5. ***Monitoring and Trending**:* Inspection results for each material, environment, and aging effect are compared to those obtained during previous inspections when available.

6. ***Acceptance Criteria**:* The acceptance criterion for this program considers both the results of each individual inspection and the compiled results of the inspections for each material, environment and aging effect combinations.

- For individual inspections, any indication or relevant conditions of degradation detected are evaluated. Acceptance criteria may be based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. For example, ultrasonic thickness measurements are compared to predetermined limits.

- For the compiled results of the inspections of each material, environment, and aging effect combination, the results must demonstrate that: (a) aging effects have not occurred; or (b) the progression of an aging effect is such that based on a projection of the observed degradation, all components in the material, environment, and aging effect combination will meet acceptance criteria at the end of the subsequent period of extended operation.

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

   Additional inspections are conducted if one of the baseline inspections does not meet acceptance criteria. The number of increased inspections is determined in accordance with the site's corrective action process; however, there are no fewer than 5 additional inspections for each baseline inspection that did not meet acceptance criteria. At multi-unit sites, the additional inspections include inspections at all of the units with the same material, environment, and aging effect combination. Where there are multiple instances of inspections not meeting acceptance criteria, a periodic inspection program is developed for the specific combination(s) of material, environment, and aging effect.

   Where the compiled results of the inspections of a material, environment, and aging effect combination does 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 any of the units on site with same combination(s) of material, environment, and aging effect.

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

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

10. ***Operating Experience***: The elements that comprise inspections associated with this program (the scope of the inspections and inspection techniques) are consistent with industry practice. An applicant's operating experience 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 where 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 operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards. Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013. [2]

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

_____. BWRVIP-03 (EPRI 105696-R6), “BWR Vessel and Internals Project: Reactor Pressure Vessel and Internals Examination Guidelines.” ML040440261. Palo Alto, California: Electric Power Research Institute. January 2004.

[2]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.

XI.M33 SELECTIVE LEACHING

Program Description

The program for selective leaching of materials ensures the integrity of the components made of gray cast iron and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc (> 15 percent Zn) or 8 percent aluminum (>8 percent Al) exposed to a raw water, closed-cycle cooling water (CCCW), treated water, waste water, soil, or ground water 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 of 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 (removal of iron from cast 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.

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 and uninhibited brass containing greater than 15 percent zinc or greater than 8 percent aluminum. These components may be exposed to raw water, CCCW, treated water, waste water, soil, or ground water.

   Dependent on plant-specific operating experience and 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 GALL-SLR Report AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”

   - The external surfaces of buried components that are externally-coated in accordance with Table XI.M41-1, of GALL-SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks,” and where direct visual examinations of buried piping in the scope of license renewal have not revealed any coating damage

   - The external surfaces of buried gray cast iron components that have been cathodically protected since installation and meet the criteria for Preventive Actions Category C in Generic Aging Lessons Learned for Subsequent License

Renewal (GALL-SLR) Report AMP XI.M41 Table XI.M41-2, “Inspections of Buried Pipe”

- The external surfaces of buried copper alloy components that meet the above cathodic protection recommendations, if 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 on preventive actions, water chemistry control consistent with GALL-SLR Report AMP XI.M2, “Water Chemistry,” or GALL-SLR Report AMP XI.M21A, “Closed Treated Water Systems,” to control pH and concentration of corrosive contaminants, and treatment to minimize dissolved oxygen 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 of and depth of dealloying through wall thickness through destructive examinations

4. ***Detection of Aging Effects**:* Inspections and examinations consist of the following:

   - Visual inspections of all accessible surfaces. In certain copper-based alloys selective leaching can be detected by visual inspection through a change in color from a normal yellow color to a reddish copper color or green copper oxide. Graphitized cast iron cannot be reliably identified through visual examination, as the appearance of the graphite surface layer created by selective leaching does not always differ appreciably from uncorroded cast iron.

   - Mechanical examination techniques, such as chipping and scraping, augment visual inspections for gray cast iron components.

   - Destructive examinations are used to determine the presence of 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. 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 operating experience 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 components) inspected. Inspections, where possible, focus on the bounding or lead components most susceptible to aging based on time-in-service and severity of operating conditions for each population.

   Opportunistic and periodic inspections are conducted for components exposed to raw water, waste water, soil, or ground water and for components in CCCW or treated water where plant-specific operating experience 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 period of extended operation. In these periodic inspections, a sample of 3 percent of the population or a maximum of 10 components per population are visually and mechanically (for gray cast iron components) inspected at each unit. When inspections are conducted on piping, a 1-foot axial length section is considered as one inspection. In addition, two destructive examinations are performed in each material and environment population in each 10-year period 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. 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 in each 10-year interval. Inspections, where possible, focus on the bounding or lead components most susceptible to aging based on time-in-service and severity of operating conditions for each population. Opportunistic inspections may be credited as periodic inspections as long as the inspection locations 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 three unit sites, seven visual and mechanical and one destructive examination are conducted at each unit. In order 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?
- Are there any systems which have had an out-of-spec water chemistry condition for a longer period of time or out-of-spec conditions occurred more frequently?
- For raw water systems, is the water source from different sources where one or the other is more susceptible to microbiologically-induced corrosion or other aging effects?

For similar environments (i.e., soil and groundwater, or raw water and waste water), 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.

Dependent on plant-specific operating experience and implementation of preventive actions, the number of inspections for certain components exposed to soil or groundwater may be adjusted as follows. When minor through-wall coating damage has been identified in plant-specific operating experience, but the components are coated in accordance with Table XI.M41-1 of GALL-SLR Report AMP XI.M41, the inspection sample size may be reduced by 50 percent of that recommended in the “detection of aging effects” program element of this AMP if the following conditions are met:

- There were no more than two instances of coating damage identified in each 10-year period of the prior operating period

- An analysis demonstrates that, if the pipe surface area affected by the coating damage is assumed to have been a through-wall hole, the pipe could be shown to meet unreinforced opening criteria of the applicable piping code

Inspections follow site procedures that include inspection parameters such as lighting, distance offset, surface coverage, presence of protective coatings, and cleaning processes that ensure an adequate examination.

5. ***Monitoring and Trending****:* Trending of destructive examination results to indicate the progression of dealloying is performed. The extent of degradation (e.g., dealloyed wall thickness, percent dealloying) is projected until the next inspection period or end of the period of extended operation to confirm the component’s intended functions will be maintained.

6. ***Acceptance Criteria****:* The acceptance criteria are: (a) for copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide; (b) for gray cast iron, the absence of a surface layer that can be easily removed by chipping or scraping or identified in the destructive examinations; and (c) components meet system design requirements such as minimum wall thickness, extended to the end of the subsequent period of extended operation.

7. ***Corrective Actions****:* Results that do not meet the acceptance criteria are addressed as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and 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. 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 acceptance criteria and a minimum of one additional destructive examination when destruction examination(s) did not meet acceptance criteria. If any of the additional inspections do not meet the acceptance criteria, the number of additional inspections continues as described above until in the last set of inspections all of the components meet the acceptance criteria.

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

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

10. ***Operating Experience****:* Operating experience shows that selective leaching has been detected in components constructed from cast iron, brass, bronze, and aluminum bronze. The following operating experience may be of significance to an applicant's program:

    a. In March 2013, a licensee submitted an American Society of Mechanical Engineers (ASME) Code Section XI relief request because it had detected weeping through aluminum bronze (susceptible to dealloying) valve bodies exposed to sea water. The degraded area was characterized by corrosion debris or wetness that returned following cleaning and drying of the surface. (ADAMS Accession Numbers 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 sand blasted 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 Number 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 (AFW) 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 preventive surveillance and periodic maintenance program. (ADAMS Accession Number 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 Number ML092400531).

e. A licensee has reported occurrences of selective leaching of aluminum bronze components for an extensive number of years. 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.g., enhanced testing, metallurgical analyses of degraded components to trend material properties). (ADAMS Accession Number ML13045A356).

f. U.S. Nuclear Regulatory Commission (NRC) Information Notice (IN) 84-71, Graphitic Corrosion of Cast Iron in Salt Water, September 06, 1984.

g. NRC IN 94-59, Accelerated Dealloying of Cast Aluminum-Bronze Valves Caused by Microbiologically Induced Corrosion, August 17, 1994.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. EPRI TR-107514, "Age Related Degradation Inspection Method and Demonstration." Electric Power Research Institute. April 1998.

Fontana, M.G. *Corrosion Engineering*. McGraw Hill. p 86-90. 1986.

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 (ASME) Code Class 1 piping. The program augments the inservice inspections (ISI) specified by ASME Code, Section XI, for certain ASME Code Class 1 piping that is less than 4 inches nominal pipe size (NPS) and greater than or equal to 1 inch NPS.

Industry operating experience 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, Subsubarticle 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 (PWR) 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 operating experience 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 means to determine 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. PWR high pressure safety injection system piping components that are subject to volumetric examinations in accordance with ASME Code, Section XI, Table IWB-2500-1, Item No. B9.22, are not within the scope of this program.

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 periodic for Category C, is based on plant-specific operating experience and whether actions that would successfully mitigate the causes of any past cracking have been implemented. Periodic examinations are implemented as per 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 those locations that are 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 operating experience, accessibility, and personnel exposure, can also be considered to select the most appropriate locations for the examinations. The guidelines from Electric Power Research Institute (EPRI) Technical Report 1011955, "Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146)," and Technical Report 1018330, "Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines–Supplemental Guidance (MRP-146S)," may be used to determine the locations that are most susceptible to thermal fatigue.

5. ***Monitoring and Trending****:* For plants that fall within Categories A and 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 those plants that fall within 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, Subsubarticle 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   The corrective actions are to include examinations of additional ASME Code Class 1 small-bore piping welds to meet the intent of ASME Code, Section XI, Subsubarticle IWB-2430. In addition, for those plants that fell within Categories A and B, periodic examinations are then implemented in accordance with the schedule specified in Category C.

8. ***Confirmation Process****:* The confirmation process is addressed through those specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the

confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

10. ***Operating Experience****:* Through-wall cracking in ASME Code Class 1 small-bore piping has occurred at a number of plants. Causes include SCC and thermal and vibratory fatigue loading as described in the U.S. Nuclear Regulatory Commission (NRC) Information Notice (IN) 97-46, "Unisolable Crack in High-Pressure Injection Piping." This program augments the ASME Code, Section XI, inspections to provide assurance that cracks will be detected before there is a loss of intended function. Licensee Event Reports (LERs) 50-259/2008-002 and LER 50-317/2012-002 provide a sample of relevant operating experience.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, "Codes and Standards." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.[1]

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

_____. EPRI Technical Report 1011955, "Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146)." Palo Alto, California: Electric Power Research Institute. June 2005.

[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.

NRC. LER 50-317/2012-002, “Reactor Coolant Pressure Boundary Leakage Due to Tubing High Cyclic Fatigue.” Washington, DC: U.S. Nuclear Regulatory Commission. September 2012.

_____. LER 50-259/2008-002 and LER 50-259/2008-002-01, “ASME Code Class 1 Pressure Boundary Leak on an Instrument Line Connected to the Reactor Vessel.” Washington, DC: U.S. Nuclear Regulatory Commission. March 2009.

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

Table XI.M35-1 Examinations

Category	Plant Operating Experience	Mitigation	Examination Schedule	Sample Size	Examination Method
A	No age-related cracking [(1) (2)]	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 [(4)] Partial penetration (socket) welds: 3% of total population per unit, up to 10 [(4)]	Volumetric or destructive [(5) (6)]
B	Age-related cracking [(2)]	Yes [(3)]	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 [(4)] Partial penetration (socket) welds: 10% of total population per unit, up to 25 [(4)]	Volumetric or destructive [(5) (6)]
C	Age-related cracking [(2)]	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 [(4)] Partial penetration (socket) welds: 10% of total population per unit, up to 25 [(4)]	Volumetric or destructive [(5) (6)]

NOTES:
(1) Must have no history of age-related cracking.
(2) Age-related cracking includes piping leaks or other flaws where fatigue or stress corrosion cracking are contributing factors.
(3) 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.
(4) The welds to be examined are selected from locations that are determined to be the most risk significant and most susceptible to cracking.
(5) Volumetric examinations must employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest.
(6) Each partial penetration (socket) weld subject to destructive examination may be credited twice towards the total number of examinations.

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. This program consists of periodic visual inspections of metallic and polymeric components, such as piping, piping components, ducting, heat exchanger components, and seals. The program manages aging effects through visual inspection of external surfaces for evidence of loss of material, cracking, fouling, changes in material properties, reduced thermal insulation resistance, and reduction of heat transfer due to fouling. When appropriate for the component and material, physical manipulation may be used to augment visual inspection to confirm the absence of elastomer hardening and loss of 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 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 Boric Acid Corrosion program [Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M10].

Evaluation and Technical Basis

1. ***Scope of Program**:* This program visually inspects the external surfaces of mechanical components for loss of material, hardening and loss of strength due to elastomer degradation, and reduction of heat transfer due to fouling and monitors the external surfaces of metallic components for leakage due to cracking. Visual inspections are conducted on insulation jacketing to ensure that the function of the thermal insulation is not impaired by moisture intrusion. Visual inspections are also conducted on outdoor insulated components, and indoor insulated components exposed to condensation (because the in-scope component is operated below the dew point) to determine whether the exterior surface of the component is degrading or has the potential to degrade. Cracking of SS and aluminum components exposed to aqueous solutions and air environments containing halides may also be managed by this program. Visual inspections or surface examinations are used to manage cracking. This program also visually inspects and monitors the external surfaces of elastomeric and polymeric components for changes in material properties (such as hardening and loss of strength), cracking, and loss of material due to wear. The program also inspects heat exchanger surfaces exposed to air for evidence of reduction of heat transfer due to fouling. Cementitious components are inspected for changes in material properties, cracking, and loss of material.

   The program also may be credited with managing loss of material from internal surfaces of metallic components and with loss of material, cracking, and change in material properties from the internal surfaces of polymers, for cases in which material and environment combinations are the same for internal and external surfaces such that external surface condition is representative of internal surface condition. When credited, the program describes the component's internal environment and the credited similar external component environment inspected.

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." 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 in-leakage 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. This program inspects components such as piping, piping components, ducting, seals, insulation jacketing, and air-side heat exchangers. For metallic components, coatings deterioration is an indicator of possible underlying degradation. Cementitious components are visually inspected for indications of changes in material properties, loss of material, and cracking.

   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 demonstrated that cracks will be detected prior to challenging the structural integrity or intended function of the component.

   Examples of inspection parameters for metallic components include:

   - Surface discontinuities and imperfections (loss of material)
   - Loss of wall thickness (loss of material)
   - Flaking or oxide-coated surfaces (loss of material)
   - Corrosion stains on thermal insulation (loss of material)
   - Protective coating degradation (cracking, flaking, and blistering)
   - Surface examinations for the detection of cracks on the external surfaces of SS and aluminum components exposed to air and aqueous solutions containing halides
   - Leakage for detection of cracks on SS and aluminum components exposed to-air and aqueous-containing halides (cracking)
   - Accumulation of debris that could impede 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.

Examples of inspection parameters for elastomers and polymers include:

- Surface cracking, crazing, scuffing, and dimensional change (e.g., "ballooning" and "necking")
- Loss of thickness
- Discoloration
- 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

4. ***Detection of Aging Effects****:* This program manages the aging effects of loss of material, cracking, changes in material properties using visual inspection, reduced thermal insulation resistance, and reduction of heat transfer due fouling. 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 (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 that ensure an adequate examination. The inspections are capable of detecting age-related degradation and 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 to manage cracking. Periodic visual inspections are conducted where it has been demonstrated that leakage or surface cracks can be detected prior to a crack challenging the structural integrity or intended function of the component. If visual inspections have not been demonstrated to effectively detect cracks prior to challenging the structural integrity or intended function of the component then a representative sample of surface examinations is conducted every 10 years during the period of extended operation. A minimum of 20 percent of the population (components having the same material, environment, and aging effect combination) or maximum of 25 components per population is inspected. The 20 percent minimum is 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.

In some instances, thermal insulation (e.g., calcium silicate) has been included in scope to reduce heat transfer from components to ensure that functions described in 10 CFR 54.4(a) are successfully accomplished. When metallic jacketing has been used, it is acceptable to conduct external visual inspections of the jacketing to ensure that there is no 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, “Aboveground Metallic Tanks”) are periodically inspected every 10 years during the 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, moist air, 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 25 1-foot axial length sections and components for each material type is inspected. 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. 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 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, and

    ii. No evidence of SCC is observed.

If: (a) the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or jacketing, (b) there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), or (c) 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 (CUI) 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 towards the inspection quantities for other types of insulation.

Visual inspection will identify indirect indicators of elastomer and flexible polymer hardening and 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 to include 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 and loss of strength for elastomers and flexible polymeric materials [e.g., heating, ventilation, and air conditioning (HVAC) flexible connectors] where appropriate. The sample size for manipulation is at least 10 percent of available surface area.

5. ***Monitoring and Trending****:* This program uses standardized monitoring and trending activities to track degradation. Deficiencies are documented using approved processes and procedures, such that results can be trended. However, the program does not include formal trending. Inspections are performed at frequencies identified in Element 4, Detection of Aging Effects.

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. Acceptance criteria are developed from plant-specific design standards and procedural requirements, 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 possible, 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 (SSCs). For example, 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 (EPRI) technical reports, TR-1007933, “Aging Assessment Field Guide,” and TR-1009743, “Aging Identification and Assessment Checklist,” provide general guidance for evaluation of materials and criteria for their acceptance when performing visual/tactile inspections.

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

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

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

10. ***Operating Experience****:* External surface inspections through system inspections and walkdowns have been in effect at many utilities since the mid-1990s in support of the Maintenance Rule (10 CFR 50.65) and have proven effective in maintaining the material condition of plant systems. The elements that comprise 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 54.4(a), “Scope.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

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

INPO. INPO Good Practice TS-413, *Use of System Engineers*. INPO 85-033. Institute of Nuclear Power Operations. May 1988.

XI.M37 FLUX THIMBLE TUBE INSPECTION

Program Description

The Flux Thimble Tube Inspection is a condition monitoring program used to inspect for 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 nondestructive examination methodology, such as eddy current testing (ECT) or other applicant-justified and the U.S. Nuclear Regulatory Commission (NRC)-accepted inspection method, is used to monitor for wear of the flux thimble tubes. This program implements the recommendations of NRC Inspection and Enforcement (IE) 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 IE Bulletin 88-09, as accepted by the staff in its closure letters on 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 on 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 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 wear of the flux thimble tubes is used to detect loss of material during the 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. 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. Wall thickness is projected using plant-specific data and a methodology that includes sufficient conservatism to

ensure that wall thickness acceptance criteria continue to be met during plant operation between scheduled inspections.

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 IE 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent Licensing Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   Flux thimble tubes with wall thickness 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 those specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

10. ***Operating Experience**:* In IE 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 IE Bulletin 88-09, which have shown excellent results in identifying and managing wear of flux thimble tubes. However, leakage events due to accelerated wear have occurred (see NRC EN Report 42822, dated August 31, 2006).

    As discussed in IE Bulletin 88-09, the amount of vibration the thimble tubes experience is determined by many plant-specific factors. Therefore, the only effective method for determining thimble tube integrity is through 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

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

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

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

Program Description

The program consists of inspections of the internal surfaces of metallic piping, piping components, and piping elements, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to uncontrolled indoor air, outdoor air, air with borated water leakage, condensation, moist air, diesel exhaust, fuel oil, lubricating oil, and any water system other than open-cycle cooling water system [age-managed by Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report aging management program (AMP) XI.M20], closed treated water system, (age-managed by GALL-SLR Report AMP XI.M21A), and fire water system (age-managed by GALL-SLR Report AMP XI.M27). However, elastomers and flexible polymeric components exposed to raw water, closed-cycle cooling water, and fire water are managed by this program. In addition, fire water system components with only a leakage boundary (spatial) or structural integrity (attached) intended function are 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 to ensure that existing environmental conditions are not causing material degradation that could result in loss of a component's intended functions. 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 conducted during the subsequent license renewal application (SLRA) development. If operating experience 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 to ensure that any recurring aging effects are adequately managed (e.g., Standard Review Plan-Subsequent License Renewal (SRP-SLR) Sections 3.2.2.2.8, 3.3.2.2.7, 3.4.2.2.6). Following 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 recurrence of the recurring internal corrosion.

Evaluation and Technical Basis

1. ***Scope of Program**:* This program includes the internal surfaces of piping, piping components, piping elements, ducting, heat exchanger components, polymeric and elastomeric 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 where loss of intended function has occurred due to age-related degradation. Cracking of SS and aluminum components exposed to aqueous solutions

and air environments containing halides may also be managed by this program. Visual inspections or surface examinations are used to manage cracking.

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: (a) loss of material and cracking of internal surfaces of metallic components, and (b) loss of material, cracking, and change in material properties from the internal surfaces of polymeric components. When credited, the program describes the component's internal environment and the credited external component's environment inspected and provides the basis to justify 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 loss of material, cracking, reduction of heat transfer due to fouling, and changes in material properties. This program monitors surface conditions or wall thickness to identify loss of material due to corrosion mechanisms for metals and loss of material due to erosion and wear for elastomers and polymers. This program also monitors for changes in visual appearance for elastomers and polymers and suppleness to identify changes in materials properties 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 demonstrated that cracks will be detected prior to challenging the structural integrity or intended function of the component.

Indicators of loss of material for metallic components include the following:

- Surface discontinuities and imperfections
- Loss of wall thickness
- Flaking or oxide-coated surfaces
- Debris from the air environment accumulating on heat exchanger tube surfaces (reduction of heat transfer due to fouling)
- Surface examinations for the detection of cracks on the surfaces of SS and aluminum components exposed to air and aqueous solutions containing halides
- Leakage for detection of cracks on the surfaces of SS and aluminum components exposed to air and aqueous solutions containing halides

- Indicators of loss of material and changes in 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

- 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

4. ***Detection of Aging Effects**:* Visual and mechanical (e.g., involving manipulation or pressurization of elastomers and flexible polymeric components) inspections conducted under this program are opportunistic in nature; they are conducted whenever piping, heat exchangers, or ducting are opened for any reason. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20 percent of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 25 components per population is inspected at each unit. Otherwise, a technical justification of the methodology and sample size used for selecting components for inspection is included as part of the program’s documentation. For multi-unit sites where the sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections at the site as follows. For two-unit sites, 19 components are inspected per unit and for a three-unit site, 17 components are inspected per unit. In order 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?

    - Are there any systems which have had an out-of-spec water chemistry condition for a longer period of time or out-of-spec conditions occurred more frequently?

    - For raw water systems, is the water source from different sources where one or the other is more susceptible to microbiologically-induced corrosion or other aging effects?

    - For components exposed to diesel exhaust, have certain diesels more operating more frequently and thus 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 most susceptible to aging because of time in service and severity of operating conditions. This minimum sample size does not override the opportunistic inspection basis of this aging management program (AMP). Opportunistic inspections continue even though in a given 10 year period, 20 percent or 25 components might have already been inspected. An inspection of a component in a more severe environment may be credited as an inspection for the specified environment and for the same material and aging effects in a less severe environment (e.g., a moist air environment is more severe than an indoor controlled air environment because the moisture in the former environment is more likely to result in 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 provided that the inspections occur on components located in the most severe environment.

Periodic visual inspections or surface examinations are conducted on SS and aluminum to manage cracking. Periodic visual inspections are conducted where it has been demonstrated that leakage or surface cracks can be detected prior to a crack challenging the structural integrity or intended function of the component. If visual inspections have not been demonstrated to effectively detect cracks prior to challenging the structural integrity or intended function of the component then a representative sample of surface examinations is conducted every 10 years during the period of extended operation. A minimum of 20 percent of the population (components having the same material, environment, and aging effect combination) or maximum of 25 components per population is inspected. The 20 percent minimum is 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.

To determine the condition of internal surfaces of buried and underground piping, inspections of the interior surfaces of accessible piping may be credited if the accessible and buried or underground component material, environment, and aging effects are similar. When inspections of the interior surfaces of accessible components with similar material, environment, and aging effects as the interior surfaces of buried or underground piping are not conducted, the sample population will be inspected using volumetric or internal visual inspections capable of detecting loss of material on the internal surfaces of the buried or underground piping.

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 (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 that ensure an adequate examination. 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 with internal reinforcement.

Manual or, physical manipulation or pressurization of flexible polymeric components is used to augment visual inspection, where appropriate, to assess loss of material or strength. The sample size for manipulation is at least 10 percent of 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****:* This program uses standardized monitoring and trending activities to track degradation. Deficiencies are documented using approved processes and procedures such that results can be trended. However, the program does not include formal trending. Inspections are performed at frequencies identified in Element 4, Detection of Aging Effects.

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, 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 possible, acceptance criteria are quantitative (e.g., minimum wall thickness, percent shrinkage allowed in an elastomeric seal). Where qualitative acceptance criteria are used, the criteria is 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, 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

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

9. ***Administrative Controls****:* Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B,

associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10. ***Operating Experience****:* Inspections of internal surfaces during the performance of periodic surveillance and maintenance activities have been in effect at many utilities in support of plant component reliability programs. These activities have proven effective in maintaining the material condition of plant SSCs. The elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and staff expectations. The applicant evaluates recent operating experience and provides objective evidence to support the conclusion that the effects of aging are adequately managed.

    The review of plant-specific operating experience 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 3.2.2.2.8, 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 operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

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

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

XI.M39 LUBRICATING OIL ANALYSIS

Program Description

The purpose of the Lubricating Oil Analysis program is to ensure that the oil environment in the mechanical systems is maintained to the required quality to prevent or mitigate age-related degradation of components within the scope of this program. This program maintains oil systems 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. Lubricating oil testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also be indicative of inleakage and corrosion product buildup.

Although primarily a sampling program, the lubricating oil analysis program is generally effective in monitoring and controlling impurities. The GALL-SLR Report identifies when the program is to be augmented to manage the effects of aging for subsequent license renewal (SLR). Accordingly, in certain cases identified in this GALL-SLR Report, verification of the effectiveness of the Lubricating Oil Analysis program is undertaken to ensure that significant degradation is not occurring and that the component's intended function is maintained during the subsequent period of extended operation. For these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system.

Evaluation and Technical Basis

1. ***Scope of Program**:* The program manages the aging effects of loss of material due to corrosion or reduction of heat transfer due to fouling. Components within the scope of the program include piping, piping components, and piping elements; 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 equipment manufacturer's recommendations or industry standards (e.g., ASTM D 6224-02). Plant-specific operating experience also may be used to augment manufacturer's recommendations or industry standards in determining the schedule for periodic sampling and testing when justified by prior sampling results.

   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 and to ensure that significant degradation is not occurring and that the component intended function is maintained during the subsequent period of extended operation.

5. ***Monitoring and Trending****:* Oil analysis results are reviewed to determine if 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this aging management program (AMP) for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

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

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

10. ***Operating Experience****:* The operating experience at some plants has identified (a) water in the lubricating oil and (b) 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 operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASTM. ASTM D 6224-02, "Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment." West Conshohocken, Pennsylvania: American Society of Testing Materials. 2002.

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

Program Description

Many neutron-absorbing materials are used in spent fuel pools. This aging management program (AMP) addresses aging management of spent fuel pools that use materials other than Boraflex, such as Boral, Metamic, boron steel, and Carborundum. Information Notice (IN) 2009-26, Degradation of Neutron-Absorbing Materials in the Spent Fuel Pool, discusses the degradation of Carborundum as well as the deformation of Boral panels in spent fuel pools. 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 (SLR).

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 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 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 with plant-specific operating experience by the licensee. The maximum interval between inspections for polymer-based materials (e.g., Carborundum, Tetrabor), regardless of operating experience, should not exceed 5 years. The maximum interval between inspections for nonpolymer-based materials [(e.g., Boral,

Metamic, Boralcan, borated stainless steel (SS)], regardless of operating experience, 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   Corrective actions are 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, which are available to maintain the subcriticality margin.

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

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

10. ***Operating Experience***: Applicants for license renewal reference plant-specific operating experience 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 operating experience that should be included 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 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 of sheet-type Carborundum.

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 operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

Letter from Christopher J. Schwarz, Entergy Nuclear Operations, Inc., Palisades Nuclear Plant, to the U.S. Nuclear Regulatory Commission, Commitments to Address Degraded Spent Fuel Pool Storage Rack Neutron Absorber. ML082410132. August 2008.

Letter from James A. Spina, Constellation Energy Nuclear Generation Group, to the U.S. Nuclear Regulatory Commission, Calvert Cliffs 1 Response to Request for Additional Information–Long-Term Carborundum Coupon Surveillance Program. ML080140341. January 2008.

Letter from Jon A. Franke, Progress Energy, 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. ML100290366. January 2010.

Letter from Kevin L. Ostrowski, FirstEnergy Nuclear Operating Company, to the U.S. Nuclear Regulatory Commission, Supplemental Information for the Review of the Beaver Valley Power Station, Units 1 and 2, License Renewal Application (TAC Nos. MD6593 and MD6594) and License Renewal Application Amendment No. 34. ML090220216. January 2009.

Letter from Mark E. Warner, FPL Energy Seabrook Station, to the U.S. Nuclear Regulatory Commission, Seabrook Station Boral Spent Fuel Pool Test Coupons Report Pursuant to 10 CFR Part 21.21, ML032880525. October 2003.

NRC. Interim Staff Guidance LR-ISG-2009-01, "Aging Management of Spent Fuel Pool Neutron-Absorbing Materials Other Than Boraflex." Washington, DC: U.S. Nuclear Regulatory Commission. 2010.

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

Southern Nuclear Operating Company. "License Renewal Application Vogtle Electric Generating Plant Units 1 and 2." ML071840360. Southern Nuclear Operating Company, Inc. June 2007.

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. This program manages aging through preventive, mitigative, inspection, and in some cases, performance monitoring activities. It manages applicable aging effects such as loss of material, cracking, and changes in material properties (for cementitious piping only).

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, hydro 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 (GALL-SLR Report AMP XI.M33) is applied in addition to this program for applicable materials and environments.

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 comprise the structural element of the component. The program addresses aging effects such as loss of material, cracking, and changes in material properties (for cementitious piping only). The program also manages loss of material due to 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.

2. ***Preventive Actions***: Preventive actions utilized 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 1 of the National Association of Corrosion Engineers (NACE) SP0169-2007 and the following:

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
Aluminum alloy	C, CP, B	None
Cementitious	C, B	None
Polymer	B	None
C: Coatings; CP: Cathodic Protection; B: Backfill		

a. For buried stainless steel or cementitious piping or tanks, coatings are provided based on the environmental conditions (e.g., stainless steel in chloride containing environments). Applicants provide justification when coatings are not provided. Coatings are in accordance with Table 1 of the National Association of Corrosion Engineers (NACE) SP0169-2007 or Section 3.4 of NACE RP0285-2002.

b. For buried steel, copper alloy, and aluminum alloy piping and tanks, and underground steel and copper alloy piping and tanks, coatings are in accordance with Table 1 of NACE SP0169-2007 or Section 3.4 of NACE RP0285-2002.

c. Cathodic protection is in accordance with NACE SP0169-2007 or NACE RP0285-2002. The system is operated so that the cathodic protection criteria and other considerations described in the standards are met at every location in the system. The system monitoring interval discussed in Section 10.3 of NACE SP0169-2007 may not be extended beyond one year. The equipment used to implement cathodic protection need not be qualified in accordance with 10 CFR Part 50, Appendix B. To prevent damage to the coating, the limiting critical potential should not be more negative than −1,200 mV.

d. Backfill is consistent with SP0169-2007 Section 5.2.3 or NACE RP0285-2002, Section 3.6. The staff considers backfill that is located within 6 inches of the component that meets ASTM D 448-08 size number 67 (size number 10 for polymeric materials) to meet the objectives of NACE SP0169-2007 and NACE RP0285-2002. For stainless steel and cementitious materials, backfill limits apply only if the component is coated. For materials other than aluminum alloy, the staff also considers the use of controlled low strength materials (flowable backfill) acceptable to meet the objectives of SP0169-2007.

e. 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 LRA.

   ii. Backfill quality may be demonstrated by plant records or by examining the backfill while conducting the inspections described in the “detection of aging effects” program element of this AMP.

   iii. For fire mains installed in accordance with National Fire Protection Association (NFPA) 24, preventive actions beyond those in NFPA 24 need not be provided if: (a) the system undergoes either a periodic flow test in accordance with NFPA 25; (b) 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 (c) 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 justified in the LRA. 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. Inspections in excess of those recommended in the “detection of aging effects” program element of this AMP may be necessary based on plant-specific operating experience.

If cathodic protection is not provided for any reason, the applicant reviews the most recent 10 years of plant specific operating experience to determine if degraded conditions that would not have met the acceptance criteria of this AMP have occurred at the facility. This search includes components that are not in-scope for license renewal if, when compared to in-scope piping, they are similar materials and coating systems and are buried in a similar soil environment. The results of this expanded plant specific operating experience search are included in the LRA.

3. ***Parameters Monitored or Inspected***:

a. Visual inspections of buried or underground piping or tanks, or their coatings, are performed to monitor for:

   i. loss of material due to general, pitting, crevice, and microbiological-induced corrosion for aluminum alloy, copper alloy, steel, stainless steel, super austenitic, and titanium alloy components;

   ii. cracking due to stress corrosion cracking for stainless steel and susceptible aluminum alloy materials;

   iii. loss of material due to wear for polymeric materials;

   iv. cracking, spalling, and corrosion or exposure of rebar for asbestos cement pipe, and concrete pipe;

   v. cracking, blistering, change in color due to water absorption for high-density polyethylene (HDPE) and fiberglass components; and

   vi. cracking due to aggressive chemical attack and leaching; changes in material properties due to aggressive chemical attack for reinforced concrete and asbestos cement piping.

b. Ultrasonic testing (UT) may be performed to monitor wall thickness. Pit depth gages, calipers or other techniques qualified for measuring wall thickness may also be used.

c. Inspections for cracking utilize a method that has been demonstrated to be capable of detecting cracking. Intact coatings do not have to be removed to inspect for potential cracking.

d. 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.

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.41-2 and the following. There are no inspection recommendations for titanium alloy, super austenitic, or nickel alloy materials. Table XI.41-2 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. Modifications to Table XI.41-2 may be appropriate if exceptions are taken to program element 2, “preventive actions,” or in response to plant-specific operating experience.

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

Table XI.M41-2. Inspection of Buried and Underground Piping and Tanks			
Inspections of Buried Piping			
Copper alloy	C	The smaller of 0.5% of the piping length or 1 inspection	
	D	The smaller of 1% of the piping length or 2 inspections	
	E	The smaller of 5% of the piping length or 3 inspections	
	F	The smaller of 10% of the piping length or 6 inspections	
Aluminum alloy	C	The smaller of 0.5% of the piping length or 1 inspection	
	D	The smaller of 1% of the piping length or 2 inspections	
	E	The smaller of 5% of the piping length or 3 inspections	
	F	The smaller of 10% of the piping length or 6 inspections	
Inspections of Buried 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; and
b. Cathodic protection has operated at least 85 percent of the time since either 10 years prior to the subsequent period of extended operation or since installation/refurbishment, whichever is shorter. Time periods in which the cathodic protection system is off-line for testing do not have to be included in the total non-operating hours; and
c. Cathodic protection has provided effective protection for buried piping as evidenced by meeting the acceptance criteria of Table XI.41-3 of this AMP at least 80 percent of the time since either 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 demonstrate 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 those portions of in-scope buried piping where the plant has demonstrated, in accordance with Section e.iv. of 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 those portions of the plant's population of buried piping where:

a. An analysis, conducted in accordance with the "preventive actions" program element of this AMP, has

Table XI.M41-2. Inspection of Buried and Underground Piping and Tanks
demonstrated 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; and
ii. Plant-specific operating experience is acceptable (i.e., no leaks in buried piping due to external corrosion, no significant coating degradation or metal loss in more than 10 percent of inspections conducted); and
iii. Soil has been demonstrated to be not corrosive for the material type. In order to demonstrate that the soil is not corrosive, the applicant:
1) Obtains a minimum of three sets of soil samples in each soil environment (e.g., moisture content, soil composition) in the vicinity in which in-scope components are buried.
2) Tests the soil for soil resistivity, corrosion accelerating bacteria, pH, moisture, chlorides, sulfates, and redox potential.
3) Determines the potential soil corrosivity for each material type of buried in-scope piping. In addition to evaluating each individual parameter, the overall soil corrosivity is determined.
4) Conducts soil testing prior to submitting the application and once in each 10-year period starting 10 years prior to the subsequent period of extended operation.
5) Provides a summary of the results and conclusions of the soil testing in the LRA.
F: Inspection criteria provided for Category F piping is used for those portions of in-scope buried piping which cannot be classified as Category C, D, or E.

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 protections 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 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 in an inspection interval cannot be credited towards the number of inspections stated in Table XI.41-2 for the 10 year interval.

b. Exceptions to Table XI.41-2 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 6 10 foot segments of steel, copper alloy, or aluminum alloy piping is inspected.

ii. For buried piping, inspections may be reduced to one-half the number of inspections indicated in Table XI.41-2 when performance of the indicated inspections necessitates excavation of piping that has been fully backfilled using controlled low strength material. The inspection quantity is rounded up (e.g., where three inspections are recommended in Table XI.41-2, two inspections are conducted). In conducting these inspections, the backfill may be excavated and the pipe examined, or the soil around the backfill may be excavated and the controlled low strength material backfill examined. The backfill 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 piping components. When conducting inspection of backfill based on the number of inspections designated for that material type, 10 linear feet of the backfill is exposed for each inspection.

iii. When Preventive Action Category A or C is met for all materials except for aluminum alloys, no inspections are necessary if all the piping constructed from a specific material type is fully backfilled using controlled low strength material.

iv. If all of the in scope polymeric material is nonsafety related, the inspection quantities for Preventive Action Category B may be reduced by half.

v. Buried polymeric tanks are only inspected if backfill is not 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 in-leakage of groundwater or rain water.

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 percentage of piping length, 10 feet of piping is exposed for each inspection.

ii. When the percentage of inspections for a given material type results in an inspection quantity of less than 10 feet, then 10 feet of piping is 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.

iii. If fire protection piping is inspected by excavations in lieu of alternative testing (e.g., flow test, jockey pump monitoring, leak rate testing) and the extent of inspections is not based on the percentage of piping in the material group, then two additional inspections are added to the inspection quantity for that material type.

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, coating condition, cathodic protection efficacy, backfill characteristics, soil resistivity, pipe contents, and pipe function are considered. For many piping systems, External Corrosion Direct Assessment (ECDA), as described in NACE SP0502-2010, "Pipeline External Corrosion Direct Assessment Methodology," has been effective in identifying pipe locations that merit further inspection. Opportunistic examinations of nonleaking pipes may be credited toward examinations if the location selection criteria are met. The use of guided wave ultrasonic or other advanced inspection techniques is encouraged for the purpose of determining the piping locations that will be inspected. These methods may not be substituted for the inspections listed in the table.

e. Alternatives to visual examination of piping are as follows:

i. Fire mains are inspected in accordance with Table XI.41-2, unless they are either: (a) subjected to a flow test as described in Section 7.3 of NFPA 25 at a frequency of at least one test in each one-year period; (b) the activity of the jockey pump (e.g., pump starts, run time) is monitored on an interval not to exceed one month; or (c) an annual system leak rate test is conducted.

ii. At least 25 percent of the in-scope piping constructed from the material under consideration is hydrostatically 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 with test pressure being held for 8 hours.

iii. At least 25 percent of the in-scope piping constructed from the material under consideration is internally inspected by a method capable of precisely determining pipe wall thickness. The inspection method has been demonstrated to be capable of detecting both general and pitting corrosion and is qualified by the applicant. UT 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. Guidance related to the extent of inspections for tanks is as follows. 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, demonstrated to be capable of detecting both general and pitting corrosion, and qualified by the applicant. 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 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.

6. ***Acceptance Criteria****:* The acceptance criteria associated with this AMP are:

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 insignificant by an individual possessing a NACE Coating Inspector Program Level 2 or 3 inspector qualification, or an individual who has attended the Electric Power Research Institute (EPRI) Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course.

b. Cracking, blistering, gouges, or wear of nonmetallic piping is evaluated.

c. Cementitious piping may exhibit minor cracking and spalling provided there is no evidence of leakage, exposed rebar, or reinforcing “hoop” bands.

d. 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).

e. Flow test results for fire mains are in accordance with NFPA 25, Section 7.3.

f. For hydrostatic 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.

g. Changes in jockey pump activity (or similar parameter) that cannot be attributed to causes other than leakage from buried piping, are not occurring.

h. When fire water system leak rate testing is conducted, leak rates are within acceptance limits of plant specific documents.

i. Criteria for soil-to-pipe potential when using a saturated CSE reference electrode is as stated in Table XI.41-3, or acceptable alternatives as stated below.

j. Alternatives to the −850 mV criterion for steel piping in Table XI.41-3 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

Table XI.M41-3. Cathodic Protection Acceptance Criteria	
Material	**Criteria[1,2]**
Steel	−850 mV relative to a CSE, instant off
Copper alloy	100 mV minimum polarization
Aluminum alloy	100 mV minimum polarization

[1]Plants with sacrificial anode systems state the test method and acceptance criteria and the basis for the method and criteria in the application.
[2]Where an impressed current cathodic protection system is utilized with prestressed concrete 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 CSE are avoided to prevent hydrogen generation and possible hydrogen embrittlement of the high-strength prestressing wire.

iii. −650 mV relative to a CSE, instant off where soil resistivity is greater than 100,000 ohm-cm

iv. Verify less than 1 mil/year (mpy) loss of material

When using the 100 mV, −750 mV, or −650 mV polarization criteria as an alternative to the −850 mV criterion for steel piping, means to verify the effectiveness of the protection of the most anodic metal is incorporated into the program. One acceptable means to verify the effectiveness of the cathodic protection system, or to demonstrate that the corrosion rate is less than 1 mpy, is to use installed electrical resistance corrosion rate probes.

The acceptance criterion (for external loss of material) to demonstrate that a cathodic protection system is operating in a satisfactory manner is 1 mpy or less. This 1 mpy criterion is related to the performance of the cathodic protection system and has no relationship to available corrosion allowances or to the remaining operational life of the piping system under consideration. Applicants separately evaluate whether a 1 mpy corrosion rate is acceptable from the perspective of the intended function (e.g., pressure boundary) of the piping under consideration. The external loss of material rate is verified:

- Every year when verifying less than 1 mpy loss of material.
- Every 2 years when using the 100 mV minimum polarization.
- Every 5 years when using the −750 or −650 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.

If electrical resistance corrosion rate probes will be used, the application states:

- The qualifications of the individuals that will determine the installation locations of the probes and the methods of use (e.g., NACE CP-4, “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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   a. Where damage to the coating has been evaluated as significant and the damage was caused by nonconforming backfill, an extent of condition evaluation is conducted to ensure that the as-left condition of backfill in the vicinity of the observed damage will not lead to further degradation.

   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 meets minimum wall thickness requirements, recommendations for expansion of sample size (see 7.c.) do not apply.

   c. Where the coatings, backfill, or the condition of exposed piping does not meet acceptance criteria, the degraded condition is repaired or the affected component is replaced. In addition, an expansion of sample size is conducted. The number of inspections within the affected piping categories are doubled or increased by 5, 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 the 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 in 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. The number of inspections may be limited by the extent of piping or tanks 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 in 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.

   d. Unacceptable cathodic protection survey results are entered into the plant corrective action program.

   e. Sources of leakage detected during pressure tests are identified and corrected.

   f. When using the alternatives to the −850 mV relative to a CSE instant off acceptance criterion for the cathodic protection system, the application states what actions will be taken if the measured external loss of material acceptance criterion, or internal loss of material rates (if opportunistic inspections are conducted by other AMPs) is exceeded.

g. When using the option of monitoring the activity of a jockey pump instead of inspecting buried fire water system piping (see 4.e.i.), 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.

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

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

10. ***Operating Experience****:* Operating experience shows that buried and underground piping and tanks are subject to corrosion. Corrosion of buried oil, gas, and hazardous materials pipelines have been adequately managed through a combination of inspections and mitigative techniques, such as those prescribed in NACE SP0169-2007 and NACE RP0285-2002. Given the differences in piping and tank configurations between transmission pipelines and those in nuclear facilities, it is necessary for the applicant to evaluate both plant-specific and nuclear industry operating experience and to modify its AMP accordingly. 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. (ADAMS Accession Number 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 Number ML093160004).

c. In April 2010, while performing inspections as part of its buried pipe program, a licensee discovered that major portions of their auxiliary feedwater (AFW) 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 Number 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 Number ML13329A422).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

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

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

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

NFPA. NFPA Standard 24, "Standard for the Installation of Private Fire Service Mains and Their Appurtenances." Quincy, Massachusetts. National Fire Protection Association. 2010.

_____. NFPA Standard 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems." Quincy, Massachusetts. National Fire Protection Association. 2008.

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.

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 ensure that the intended functions of in scope components are met. Degradation of coatings/linings can lead to loss of material of base materials and downstream effects such as reduction in flow, reduction in pressure, or reduction in 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, waste water, fuel oil, and lubricating oil. Where the visual inspection of the coated/lined surfaces determines that the coating/lining is deficient or degraded, physical tests are performed, where physically possible, in conjunction with the visual inspection. Electric Power Research Institute (EPRI) Report 1019157, "Guideline on Nuclear Safety Related Coatings," provides information on the American Society for Testing and Materials (ASTM) standard guidelines and coatings. American Concrete Institute (ACI) Standard 201.1R 08, "Guide for Conducting a Visual Inspection of Concrete in Service," provides guidelines for inspecting concrete.

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, and lubricating oil 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 10 CFR 54.4(a)(1), (a)(2), or (a)(3). The aging effects associated with fire water tank internal coatings/linings are managed by Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) aging management program (AMP) XI.M27, "Fire Water System," instead of this AMP. However, where the fire water 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 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 as shown in Standard Review Plan-Subsequent License Renewal (SRP-SLR) Table 3.0-1, "FSAR Supplement for Aging Management of Applicable Systems," is included in the application with a reference to the alternative AMP.

For components where 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.

2. ***Preventive Actions****:* The program is a condition monitoring program and does not recommend any preventive actions.

3. ***Parameters Monitored or Inspected****:* Visual inspections are intended to identify coatings/linings that do not meet acceptance criteria, such as peeling and delamination. Aging mechanisms associated with coatings/linings are described 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
- Spalling–a fragment, usually in the shape of a flake, detached from a concrete member.

Physical damage consists of removal or reduction of the thickness of 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 assembly and disassembly of flanged joints.

Physical testing is intended to identify the extent of potential degradation of the coating/lining.

4. ***Detection of Aging Effects****:* Baseline coating/lining inspections occur in 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 inscope component's intended function, potential problems identified during prior inspections, and known service life history. Subsequent inspection intervals are established by a coating specialist qualified in accordance with an ASTM International standard endorsed in Regulatory Guide (RG) 1.54. However, inspection intervals should not exceed those in Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers."

The extent of baseline and periodic inspections is based on an evaluation of the effect of a coating/lining failure on the in-scope component's intended function(s), potential problems identified during prior inspections, and known service life history; however, the extent of inspection is not any less than the following for each coating/lining material and environment combination.

- All tanks–all accessible internal surfaces
- All heat exchangers–all accessible internal surfaces
- Piping–either inspect a representative sample of 73 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating/lining material and environment combination, whichever is less at each unit. The inspection surface includes the entire inside surface of the 1-foot sample. If geometric limitations impede movement of remote or robotic inspection tools, the number of inspection segments is increased in order to cover an equivalent of 73 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 is inspected.

  Where documentation exists that manufacturer recommendations and industry consensus documents (i.e., those recommended in RG 1.54, or earlier versions of those standards) were complied with during installation, the extent of piping inspections may be reduced to the lesser of 25 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.

For multiunit 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:

Table XI.M42-1. Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers[1, 6]	
Inspection Category[2]	**Inspection Interval**
A	6 years[3]
B[4,5]	4 years

1. CLB requirements (e.g., Generic Letter 89-13) might require more frequent inspections.
2. Inspection Categories
   A. No peeling, delamination, blisters, or rusting are observed during inspections. Any cracking and flaking has been found acceptable in accordance with the “acceptance criteria” program element of this AMP. No cracking or spalling in cementitious coatings/linings.
   B. Prior inspection results do not meet Category A.
   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 inspects either double the number of components or an additional 5 piping inspections (i.e., 5 1-foot segments of piping). If Inspection Category A criteria is satisfied for the other coatings in the initial sample and the expanded scope, Inspection Category A may be used for subsequent inspections.
3. If the following conditions are met, the inspection interval may be extended to 12 years:
   a. 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.
   b. The coating/lining is not in a location subject to erosion that could result in mechanical damage to the coating/lining (e.g., certain heat exchanger end bells, piping downstream of certain control valves).
4. 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.
5. 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 to Inspection Category A.
6. Internal inspection intervals for diesel fuel oil storage tanks may meet either Table XI.42-1, or if the inspection results meet Inspection Category A, GALL-SLR Report AMP XI.M30, “Fuel Oil Chemistry.”

- For two-unit sites, 55 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, 49 1-foot axial length sections of piping (17 if manufacturer recommendations and industry consensus documents were complied with during installation) are inspected per unit.

  In order 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, temperature, excursions) to provide representative inspection results.

The coating/lining environment includes both the environment inside 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 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 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 in 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 LR 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-induced 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, and
- The design for 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. The grid dimensions for the representative sample should be consistent with those for inspections for flow-accelerated corrosion.

  (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, GALL-SLR Report AMP XI. GALL-SLR Report M21A) to manage loss of coating or lining integrity.

In addition, where loss of coating or lining integrity cannot result in downstream effects such as reduction in flow, drop in pressure, or reduction in heat transfer for in-scope components, a representative sample of external wall thickness measurements can be 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. A representative sample size is described above with grid dimensions being those consistent with inspections for flow-accelerated corrosion.

The training and qualification of individuals involved in coating/lining inspections and evaluating degraded conditions is conducted in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with a particular standard, except for cementitious materials. For cementitious coatings/linings inspectors should have a minimum of 5 years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of 1 year of experience.

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. When corrosion of the base material is the only issue related to coating/lining degradation of the component and external wall thickness measurements are used in lieu of internal visual inspections of the coating/lining, the corrosion rate of the base metal is trended.

6. ***Acceptance Criteria**:* Acceptance criteria are as follows:

   a. There are no indications of peeling or delamination.

   b. Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size and frequency should not be increasing between inspections (e.g., ASTM D714-02, "Standard Test Method for Evaluating Degree of Blistering of Paints").

   c. Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard.

   d. Minor cracking and spalling of cementitious coatings/linings is acceptable provided 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 design minimum wall 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   Coatings/linings that do not meet 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, coatings exhibiting indications of peeling and delamination may be returned to service if: (a) physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal; (b) 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); (c) adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of 3 sample points adjacent to the defective area; (d) 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 (e) followup 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 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 if the minimum wall thickness is met and will be met until the next inspection.

   If a blister is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain in-service should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister.

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

9. ***Administrative Controls**:* Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B,

associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10. ***Operating Experience**:* The inspection techniques and training of inspection personnel associated with this program are consistent with industry practice and have been demonstrated effective at detecting loss of coating or lining integrity. Not to exceed inspection intervals have been established that are dependent on the results of previous plant specific inspection results. The following examples describe operating experience 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 contains many key aspects related to coating degradation. These include 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 to manufacturer recommendations resulted in flow restrictions to the ultimate heat sink and blockage of an emergency diesel generator governor oil cooler. [Information Notice (IN) 85-24, “Failures of Protective Coatings in Pipes and Heat Exchangers”].

    b. During an U.S. Nuclear Regulatory Commission (NRC) inspection, the staff found that coating degradation, which occurred as a result of 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. (ADAMS Accession Number 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 had lack of adhesion to the base metal. In 2011, diminished flow was observed downstream of this line. Inspections revealed that a majority 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 in service sample as compared to an unused sample. (ADAMS Accession Number 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 Number 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 due to the rubber coating on a butterfly valve becoming detached. (ADAMS Accession Number 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 Number 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 Number 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 been nonage related mechanical damage. (ADAMS Accession Number ML14087A210).

i. A licensee experienced through wall corrosion when a localized polymeric repair of a rubber lined spool failed. (ADAMS Accession Number 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 Number ML12297A333).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 54.4(a), “Scope.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

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

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

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

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

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

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

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

XI.S1 ASME SECTION XI, SUBSECTION IWE

Program Description

10 CFR 50.55a imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code[1], Section XI, Subsection IWE, for steel containments (Class MC) and steel liners for concrete containments (Class CC). The scope of Subsection IWE includes steel containment shells and their integral attachments, steel liners for concrete containments and their integral attachments, containment penetrations, hatches, airlocks, moisture barriers, and pressure-retaining bolting. The requirements of ASME Code, Section XI, Subsection IWE, with the additional requirements specified in 10 CFR 50.55a(b)(2), are supplemented herein to constitute an existing program applicable to managing 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 is 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 ensure emergency core cooling system (ECCS) operability, whether or not the GALL-SLR Report AMP XI.S8 is credited in GALL-SLR Report AMP XI.S1.

The program attributes are supplemented to incorporate aging management activities, recommended in the Final Interim Staff Guidance LR-ISG-2006-01, 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 attributes also are supplemented to recommend surface or augmented examination of two-ply bellows for detection of cracking described in the U.S. Nuclear Regulatory Commission (NRC) Information Notice (IN) 92-20, “Inadequate Local Leak Rate Testing,” and to include preventive actions to ensure bolting integrity. The program is also supplemented to perform surface examination of stainless steel (SS) and dissimilar metal welds of penetration sleeves, penetration bellows, vent line bellows; and volumetric examination of metal shell or liner surfaces that are inaccessible from one side, during each inspection interval.

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 are 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

[1]Refer to the GALL Report, Chapter I, for applicability of other editions of the ASME Code, Section XI.

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. XI.S8 is a protective coating monitoring and maintenance program that is recommended to ensure 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, provided the requirements of IWE-1232 and IWE-5220 are met; and

(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) and IWE-2420 (2006 and later editions/addenda) specify additional requirements for inaccessible areas. It states 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 to such inaccessible areas. Examination requirements for containment supports are not within the scope of Subsection IWE.

2. ***Preventive Action**:* The ASME Code Section XI, Subsection IWE, is a condition monitoring program. The program is supplemented to include preventive actions that ensure 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 ensure bolting integrity, as discussed in Electric Power Research Institute (EPRI) documents (such as EPRI NP-5067 and TR-104213), American Society for Testing and Materials (ASTM) standards, and American Institute of Steel Construction (AISC) specifications, as applicable. The preventive actions 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), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in

Section 2 of Research Council for Structural Connections (RCSC) publication "Specification for Structural Joints Using High-Strength Bolts," need to be considered.

3. ***Parameters Monitored or Inspected****:* Table IWE-2500-1 references the applicable sections in IWE-2300 and IWE-3500 that identify the parameters examined or monitored. Noncoated surfaces are examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, liner plate bulges, and other signs of surface irregularities. Painted or coated surfaces, including those inside BWR suppression chambers, are examined for evidence of flaking, blistering, peeling, discoloration, liner bulges, and other signs of potential distress of the underlying metal shell or liner. Stainless steel (SS) and dissimilar metal welds of penetration sleeves, penetration bellows, and vent line bellows; and steel bellows components that are subject to cyclic loading but have no current licensing basis (CLB) fatigue analysis, 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 and Subsection IWE ensure 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. The acceptability of inaccessible areas of the steel containment shell or concrete containment steel liner is evaluated when conditions are found in accessible areas that 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 subject to or susceptible to accelerated degradation. 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. Liner plate bulges should be evaluated for corrosion potential.

   The requirements of ASME Section XI, Subsection IWE and 10 CFR 50.55a are supplemented to perform surface examination, in addition to visual examination, to detect cracking in (a) SS and dissimilar metal welds of penetration sleeves, penetration bellows, and vent line bellows; and (b) steel bellows components that are subject to cyclic loading but have no CLB fatigue analysis. The supplemental surface examination of dissimilar metal welds may be performed in accordance with Table IWE-2500-1, Examination Category E-F, as specified in the 1995 edition with 1996 addenda of the

ASME Code, Section XI, Subsection IWE. Components for which supplemental surface examination is not feasible are identified and appropriate Appendix J leak rate tests (GALL-SLR Report AMP XI.S4) justified to detect cracking are conducted in lieu of the supplemental surface examination. For two-ply bellows of the type described in NRC IN 92-20 for which it is not possible to perform a valid local leak rate test, augmented examination using qualified enhanced techniques that can detect cracking is recommended.

The requirements of ASME Section XI, Subsection IWE and 10 CFR 50.55a are further supplemented to require volumetric examination of metal shell or liner surfaces that are inaccessible from one side, during each inspection interval. The supplemental examination consists of (1) a sample of one-foot square randomly selected locations and (2) a sample of one-foot square locations focused on areas most likely to experience degradation. The sample size, locations, frequency and schedule for each set of volumetric examinations should be determined on a plant-specific basis during each interval.

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:

(a) The sequence of component examinations established during the first inspection interval shall be repeated during successive intervals, to the extent practical.

(b) 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.

(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 operating experience.

(a) Develop a corrosion rate that can be inferred from past ultrasonic testing (UT) examinations or establish a corrosion rate using representative samples in similar operating conditions, materials, and environments. If degradation has occurred, provide a technical basis using the developed or established corrosion rate to demonstrate that the drywell shell will have sufficient wall thickness to perform its intended function through the subsequent period of extended operation.

(b) Demonstrate that UT measurements performed in response to NRC Generic Letter (GL) 87-05, “Request for Additional Information Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells” did not show degradation inconsistent with the developed or established corrosion rate.

6. ***Acceptance Criteria****:* IWE-3000 provides acceptance standards for components of steel containments and liners of concrete containments. IWE-3410 refers to criteria to evaluate the acceptability of the containment components for service following the preservice examination and each inservice examination. Most of the acceptance standards rely on visual examinations. Areas that are suspect 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 are documented. Such areas are corrected by repair or replacement in accordance with IWE-3122 or accepted by engineering evaluation. Cracking of SS and dissimilar metal welds of penetration sleeves, penetration bellows, and vent line bellows; and steel bellows components that are subject to cyclic loading but have no CLB fatigue analysis is corrected by repair or replacement or accepted by engineering evaluation. Where applicable, the program should establish quantitative acceptance criteria for containment liner bulges consistent with the CLB for the liner.

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

   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 reexaminations 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:

(a) Include in the scope of 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 (AMR).

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

When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. If the evaluation determines that repair or replacement is necessary, Subsection IWE specifies confirmation that appropriate corrective actions have been completed and are effective. Subsection IWE states that repairs and re-examinations are to comply with the requirements of IWA-4000. Re-examinations are conducted in accordance with the requirements of IWA-2200, and the recorded results are to demonstrate that the repair meets the acceptance standards set forth in IWE-3500.

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

IWA-6000 provides specifications for the preparation, submittal, and retention of records and reports.

10. ***Operating Experience**:* ASME Section XI, Subsection IWE, was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to

degradation of steel components of containment was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the NRC. NRC IN 86-99, IN 88-82, IN 89-79, IN 2004-09, IN 2010-12 and NUREG–1522 described occurrences of corrosion in steel containment shells and containment liners. NRC GL 87-05 addressed the potential for corrosion of BWR Mark I steel drywells in the “sand pocket region.” IN 2011-15 described occurrences of corrosion in BWR Mark I steel containments, both inside the suppression chamber (torus) and outside the drywell. IN 2014-07 described operating experience concerning degradation of floor weld leak-chase channel systems of the steel containment shell and concrete containment steel liner that could affect leak tightness and aging management of containment structures.

NRC IN 97-10 identified specific locations where concrete containments are susceptible to liner plate corrosion; IN 92-20 described instances of two-ply containment bellows cracking for which leak rate testing was inadequate for detection, resulting in loss of leak tightness. Based on occurrences of transgranular stress corrosion cracking (SCC), NUREG–1611 (Tables 1 and 2) recommends augmented examination on the surfaces of two-ply bellow bodies using qualified enhanced techniques so that cracking can be detected. Other operating experience indicates that foreign objects embedded in concrete have caused through-wall corrosion of the liner plate at a few plants with reinforced concrete containments. NRC Technical Report, “Containment Liner Corrosion Operating Experience Summary” dated August 2, 2011, summarizes the industry operating experience related to containment liner corrosion and containment liner bulges.

NRC IN 2006-01 described through-wall cracking and its probable cause in the torus of a BWR Mark I containment. The cracking was identified by the licensee in the heat-affected zone at the high-pressure coolant injection (HPCI) turbine exhaust pipe torus penetration. The licensee concluded that the cracking was most likely initiated by cyclic loading due to condensation oscillation during HPCI operation. These condensation oscillations induced on the torus shell may have been excessive due to a lack of an HPCI turbine exhaust pipe sparger that many licensees have installed.

The program is to consider the liner plate and containment shell corrosion and cracking concerns described in these generic communications and technical report. Implementation of the ISI requirements of Subsection IWE, in accordance with 10 CFR 50.55a, augmented to consider operating experience, and as recommended in LR-ISG-2006-01, is a necessary element of aging management for steel components of steel and concrete containments through the subsequent period of extended operation.

Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, stress corrosion cracking (SCC), and fatigue loading (NRC IE Bulletin 82-02, NRC GL 91-17). SCC has occurred in high strength bolts used for nuclear steam supply system component supports (EPRI NP-5769).

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR Part 50, Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWA, General Requirements.” The ASME Boiler and Pressure Vessel Code New York, New York: The American Society of Mechanical Engineers. 2013.[2]

_____. ASME 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.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.

_____. ASME 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.” The ASME Boiler and Pressure Vessel Code, New York, New York: The American Society of Mechanical Engineers. 2013.

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

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

NRC. NRC Information Notice 2014-07, “Degradation of leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner.” ML14070A114. Washington, DC: U.S. Nuclear Regulatory Commission. May 2014.

_____. NRC Technical Report, “Containment Liner Corrosion Operating Experience Summary.” ML112070867. Revision 1. Washington, DC: U.S. Nuclear Regulatory Commission. August 2011.

_____. NRC Information Notice 2011-15, “Steel Containment Degradation and Associated License Renewal Aging Management Issues.” ML111460369. Washington, DC: U.S. Nuclear Regulatory Commission. August 2011.

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

_____. NRC Information Notice 2010-12, “Containment Liner Corrosion.” Washington, DC: U.S. Nuclear Regulatory Commission. June 2010.

_____. NRC Information Notice 2006-01, “Torus Cracking in a BWR Mark I Containment.” ML053060311. Washington, DC: U.S. Nuclear Regulatory Commission. January 2006.

_____. Staff Position and Rationale for the Final License Renewal Interim Staff Guidance LR-ISG-2006-01, “Plant-Specific Aging Management Program for Inaccessible Areas of Boiling Water Reactor (BWR) Mark I Steel Containments Drywell Shell.” Washington, DC: U.S. Nuclear Regulatory Commission. November 2006.

_____. NRC Information Notice 2004-09, “Corrosion of Steel Containment and Containment Liner.” ML041170030. Washington DC: U.S. Nuclear Regulatory Commission. April 2004.

_____. NRC Information Notice 97-10, “Liner Plate Corrosion in Concrete Containment.” ML031050365. Washington, DC: U.S. Nuclear Regulatory Commission. March 1997.

_____. NUREG–1611, “Aging Management of Nuclear Power Plant Containments for License Renewal.” ML071650341. Washington, DC: U.S. Nuclear Regulatory Commission. September 1997.

_____. NUREG–1522, “Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures.” ML06510407. Washington, DC: U.S. Nuclear Regulatory Commission. June 1995.

_____. NRC Information Notice 92-20, “Inadequate Local Leak Rate Testing.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1992.

_____. NRC Generic Letter 91-17, “Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants.” ML0311140534. Washington, DC: U.S. Nuclear Regulatory Commission. October 1991.

_____. NRC Information Notice 86-99, “Degradation of Steel Containments.” ML031250248, ML 031250234. Washington, DC: U.S. Nuclear Regulatory Commission, December 8, 1986. Supplement 1 February 1991.

_____. NRC Information Notice 89-79, “Degraded Coatings and Corrosion of Steel Containment Vessels.” ML031190089. Washington, DC: U.S. Nuclear Regulatory Commission. December 1989. Supplement 1 June 1989.

_____. NRC Information Notice 88-82, “Torus Shells with Corrosion and Degraded Coatings in BWR Containments.” ML031150069, ML082910476. Washington, DC: U.S. Nuclear Regulatory Commission. October 1988. Supplement 1 May 1989.

_____. NRC Generic Letter 87-05, “Request for Additional Information Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells.” ML031140335. Washington, DC: U.S. Nuclear Regulatory Commission. March 1987.

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

Research Council on Structural Connections. “Specification for Structural Joints Using High-Strength Bolts.” December 2009.

XI.S2 ASME SECTION XI, SUBSECTION IWL

Program Description

10 CFR 50.55a imposes the examination requirements of the American Society of Mechanical Engineers (ASME) Boling and Pressure Vessel (B&PV) 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 aging of containment reinforced concrete and unbonded post-tensioning systems, and supplemented herein, for subsequent license renewal (SLR). Containments with grouted tendons may require an additional plant-specific aging management program (AMP), based on the guidance in U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.90, “Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons,” to address the adequacy of prestressing forces.

The primary inspection method specified in IWL-2500 is visual examination, supplemented by testing. For prestressed containments, tendon wires are tested for yield strength, ultimate tensile strength, and elongation. 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 is 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 is found.

The 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 unbonded post-tensioning systems of Class CC containments, as defined by CC-1000. The program also includes testing of the tendon corrosion protection medium and the pH of free water. Subsection IWL exempts from examination portions of the concrete containment that are inaccessible (e.g., concrete covered by liner, foundation material, or backfill or obstructed by adjacent structures or other components).

   10 CFR 50.55a(b)(2)(viii) and the 2009 and later editions/addenda of the 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 to such inaccessible areas. Steel liners for concrete containments and their integral attachments

---

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

are not within the scope of Subsection IWL but are included within the scope of Subsection IWE. Subsection IWE is evaluated in GALL-SLR Report AMP XI.S1, “ASME Section XI, Subsection IWE.”

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 IWL.

3. ***Parameters Monitored or Inspected****:* Table IWL-2500-1 specifies two categories for examination of concrete surfaces: (i) Category L-A for all accessible concrete surfaces and (ii) Category L-B for concrete surfaces surrounding anchorages of tendons selected for testing in accordance with IWL-2521. Both of these categories rely on visual examination methods. Concrete surfaces are examined for evidence of damage or degradation, such as concrete cracks. IWL-2510 specifies that concrete surfaces are examined for conditions indicative of degradation, such as those defined in American Concrete Institute (ACI) 201.1R and ACI 349.3R. Table IWL-2500-1 also specifies Category L-B for test and examination requirements for unbonded post tensioning systems. The number of tendons selected for examination is in accordance with Table IWL-2521-1. Additional augmented examination requirements for post-tensioning system repair/replacement activities are to be 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 and Subsection IWL ensure 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 at 1, 3, and 5 years following 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 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 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 are recorded and trended for all applicable parameters monitored or inspected, and the use of photographs or surveys is recommended. Photography and its variations may be used to trend aging effects such as cracking, spalling, delamination, pop-outs, or other age-related concrete degradation as illustrated in ACI 201.1R. Photographic records may be used to document and trend the type, severity, extent and progression of degradation.

   For prestressed containments, trending of prestressing forces in tendons is required in accordance with the acceptance by examination criteria in IWL-3220. In addition to the random sampling used for tendon examination, one tendon of each type is selected from the first-year inspection sample and designated as a common tendon. Each common tendon is then examined during each inspection. Corrosion protection medium chemistry and free water pH are monitored for each examined tendon. This procedure provides monitoring and trending information over the life of the plant. 10 CFR 50.55a 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 criteria for concrete containments. In addition, this program includes quantitative acceptance criteria for concrete surfaces based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R.

   The acceptance standards for the unbonded post-tensioning system are quantitative in nature. For the post-tensioning system, quantitative acceptance criteria are given for tendon force and elongation, tendon wire or strand samples, and corrosion protection medium. Free water in the tendon anchorage areas is not acceptable, as specified in IWL-3221.3. If free water is found, the recommendations in Table IWL-2525-1 are followed. 10 CFR 50.55a and Subsection IWL do not define the method for calculating predicted tendon prestressing forces for comparison to the measured tendon lift-off forces. The predicted tendon forces are calculated in accordance with RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments," which provides an acceptable methodology for use through the subsequent period of extended operation.

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

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

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

   IWA-1400 specifies the preparation of plans, schedules, and inservice inspection (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 Section XI, Subsection IWL was incorporated into 10 CFR 50.55a in 1996. Prior to this 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 pertaining to degradation of reinforced concrete in concrete containments was gained through the inspections required by 10 CFR 50.55a(g)(4) (i.e., Subsection IWL), 10 CFR Part 50, Appendix J, and ad hoc inspections conducted by licensees and the NRC. NUREG–1522, "Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures," described instances of cracked, spalled, and degraded concrete for reinforced and prestressed concrete containments. The NUREG also described cracked anchor heads for the prestressing tendons at three prestressed concrete containments. NRC IN 99-10, Rev. 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," describes issues concerning the containment concrete surface condition examination frequency and acceptance criteria. The program considers the degradation concerns described in these generic communications. Implementation of Subsection IWL, in accordance with 10 CFR 50.55a, is a necessary element of aging management for concrete containments through the subsequent period of extended operation.

    NRC Inspection Report 05000302/2009007 documents operating experience 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 operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR Part 50, Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

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

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWA, General Requirements.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers.[2] 2013.

_____. ASME 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.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.

_____. ASME 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.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.

NRC. NRC Regulatory Guide 1.90, “Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons.” ML11249A008. Washington, DC: U.S. Nuclear Regulatory Commission. November 2012.

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

_____. NRC Information Notice 2010-14, “Containment Concrete Surface Condition Examination Frequency and Acceptance Criteria.” ML101600151. Washington, DC: U.S. Nuclear Regulatory Commission. August 2010.

_____. NRC Information Notice 99-10, Revision 1, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment.” Revision 1. ML031500244. Washington DC: U.S. Nuclear Regulatory Commission. April 1995.

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

_____. NRC Regulatory Guide 1.35.1, “Determining Prestressing Forces for Inspection of Prestressed Concrete Containments.” ML0037400403. Washington, DC: U.S. Nuclear Regulatory Commission. July 1990.

_____. NRC Regulatory Guide 1.35, “Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments.” ML003740007. Washington, DC: U.S. Nuclear Regulatory Commission. July 1990.

XI.S3 ASME SECTION XI, SUBSECTION IWF

Program Description

The 10 CFR 50.55a, imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (B&PV),[1] Section XI, for Class 1, 2, 3, and metal containment (MC) piping and components and their associated supports. ISI of supports for ASME piping and components is addressed in Section XI, Subsection IWF. 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 aging of containment reinforced concrete and unbonded post-tensioning systems, and supplemented by guidance herein, for subsequent license renewal (SLR). This evaluation covers the 2004 edition of the ASME Code as approved in 10 CFR 50.55a. This program supplements ASME Code, Section XI, Subsection IWF, which constitutes an existing mandated program applicable to managing aging of ASME Class 1, 2, 3, and MC component supports for subsequent license renewal (SLR).

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 Class 2 and 3). Discovery of support deficiencies during regularly scheduled inspections triggers an increase of the inspection scope in order to ensure that the full extent of deficiencies is identified. The primary inspection method employed is visual examination. Degradation that potentially compromises support function or load capacity is identified for evaluation. ASME 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) or 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 inspections of randomly selected additional supports for each group of materials used and the environments to which they are exposed outside of the existing 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 or 1,034 MPa), anchor bolts, 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

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

conditions exist in accessible areas that could indicate the presence of, or result in, degradation to 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, molybdenum disulfide and other lubricants containing sulfur should not be used. Preventive measures also include using bolting material that has actual measured yield strength less than 150 ksi or 1,034 MPa. Bolting replacement and maintenance activities include proper selection of bolting material and lubricants, and appropriate installation torque or tension, as recommended in Electric Power Research Institute (EPRI) documents (e.g., EPRI NP-5067 and EPRI TR-104213), American Society for Testing and Materials (ASTM) standards, and American Institute of Steel Construction (AISC) 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), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of Research Council for Structural Connections (RCSC) publication "Specification for Structural Joints Using High-Strength Bolts" need to be used.

3. ***Parameters Monitored or Inspected**:* The parameters monitored or inspected include corrosion; deformation; misalignment of supports; missing, detached, or loosened support items; cracking of welds; 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 vibration isolation elements are monitored for cracking, loss of material, and hardening. All bolting within the scope of the program is monitored for corrosion, loss of integrity of bolted connections due to self-loosening, and material conditions that can affect structural integrity. In addition, the concrete around anchor bolts is monitored for cracking. High strength bolting in sizes greater than 1 inch nominal diameter, including ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or 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, plus an additional 5 percent of Class 1, 2, and 3 piping supports. The additional supports are randomly selected from the remaining population of IWF piping supports. The extent, frequency, and examination methods 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, 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 vibration isolation elements. Elastomeric 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 which exceed acceptance

criteria may be supplemented by either surface or volumetric examinations to determine the character of the flaw.

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 performed to detect cracking in addition to the VT-3 examination. This volumetric examination may be waived with plant-specific justification. High-strength ASTM A325, and/or ASTM A490 bolting (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), in sizes greater than 1 inch nominal diameter, within the scope of this program is not exempt from volumetric examination unless additional justification is provided.

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 whose examinations reveal unacceptable conditions and 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 which 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 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; and

(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; and

(d) Loss of material, cracking, and hardening of elastomeric vibration isolation elements that could reduce the vibration isolation function.

The above conditions may be accepted provided the technical basis for their acceptance is documented.

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

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

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

10. ***Operating Experience:*** Degradation of threaded bolting and fasteners has occurred from boric acid corrosion, SCC, and fatigue loading U.S. Nuclear Regulatory Commission (NRC) Inspection and Enforcement (IE) Bulletin 82-02, "Degradation of Threaded Fasteners In the Reactor Coolant Pressure Boundary of PWR Plants," NRC Generic Letter (GL) 91-17, "Generic Safety Issue 79, Bolting Degradation of Failure in Nuclear Power Plants"). SCC has occurred in high-strength bolts used for nuclear steam supply system (NSSS) component supports (EPRI NP-5769). NRC Information Notice (IN) 2009-04 describes deviations in the supporting forces of mechanical constant

supports, from code allowable load deviation, due to age-related wear on the linkages and increased friction between the various moving parts and joints within the constant support, which can adversely affect the analyzed stresses of connected piping systems.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants. Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, “Codes and Standards.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWB, Requirements for Class 1 Components of Light-Water Cooled Power Plants.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.[2]

_____. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWC, Requirements for Class 2 Components of Light-Water Cooled Power Plants.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.

_____. ASME Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components, Subsection IWD, Requirements for Class 3 Components of Light-Water Cooled Power Plants.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.

_____. ASME 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.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.

_____. ASME 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.” The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.

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

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

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

NRC. NRC Information Notice 2009-04, “Age-Related Constant Support Degradation.” ML090340754. Washington, DC: U.S. Nuclear Regulatory Commission. February 2009.

_____. NRC Generic Letter 91-17, “Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants.” ML031140534. Washington, DC: U.S. Nuclear Regulatory Commission. October 1991.

_____. NRC IE Bulletin 82-02, “Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants.” ML03120720. Washington, DC: U.S. Nuclear Regulatory Commission. June 1982.

Research Council on Structural Connections. “Specification for Structural Joints Using High-Strength Bolts.” 2009.

XI.S4 10 CFR PART 50, APPENDIX J

Program Description

A typical primary reactor containment system consists of a containment structure (containment), and a number of electrical, mechanical, equipment hatch, and personnel air lock penetrations. As described in Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," (Appendix J) periodic containment leak rate tests are required to ensure that (a) leakage through these containments or systems and components penetrating these containments does not exceed allowable leakage rates specified in the Technical Specification (TS) and (b) integrity of the containment structure is maintained during its service life.

This aging management program (AMP) credits the existing program required by 10 CFR Part 50 Appendix J, and augments it to ensure that all containment pressure-retaining components are managed for age-related degradation.

Appendix J provides two options, Option A and Option B, to meet the requirements of a containment leak rate test (LRT) program. Option A is prescriptive with all testing performed on specified periodic intervals. Option B is a performance-based approach. The U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program" and Nuclear Energy Institute (NEI) 94-01, Industry Guideline for Implementing Performance-Based Option for 10 CFR Part 50, Appendix J, as approved by the NRC final safety evaluation for NEI 94-01, Revision 3, 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 (ILRTs) determine the overall containment integrated leakage rate, at the calculated peak containment internal pressure (Pa) related to the design basis loss of coolant accident (LOCA). 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. If Type C tests are not performed under this program, they could be included under an Inservice Testing Program for systems containing the isolation valves [e.g., American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Power Plants (NPPs) or ASME Code, Section XI, Division 1, Rules for inservice inspection (ISI) of NPP Components, incorporated by reference in 10 CFR 50.55a].

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 ASME Section XI, Subsection IWE and ASME Section XI, Subsection 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. Containment pressure-retaining boundary components within the scope of subsequent license renewal (SLR) and excluded from Appendix J testing must still be age-managed. Other programs may be credited for aging management of these components; however, 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 leakage rates of the containment pressure boundary components, including seals and gaskets, and in identifying and correcting sources of leakage. While the calculation of leakage rates and satisfactory performance of containment leak rate testing demonstrates 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. This would be achieved with the implementation of acceptable containment ISI programs such as ASME Section XI, Subsection IWE (GALL-SLR Report AMP XI.S1), and ASME 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 to adjust 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 TS 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related 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 those specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

   Results of the containment LRT program are documented as described in Appendix J, to demonstrate that the acceptance criteria for leakage rates have been satisfied. The test results that exceed the acceptance criteria are assessed under 10 CFR 50.72 and 10 CFR 50.73.

10. ***Operating Experience****:* To date, 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.

   The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

   NRC Information Notice (IN) 92-20, "Inadequate Local Leak Rate Testing," describes operating experience of inadequate local leak rate testing of two-ply steel expansion bellows that were used on some piping penetrations.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.55a, "Codes and Standards." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.72, "Immediate Notification Requirements for Operating Nuclear Power Reactors." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.73, "Licensee Event Report System." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASME. ASME 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." The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.

_____. ASME 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." The ASME Boiler and Pressure Vessel Code. New York, New York: The American Society of Mechanical Engineers. 2013.

NEI. NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J." Rev. 3-A. ML12221A202. Nuclear Energy Institute. July 2012.

_____. NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J." Rev. 2-A. Nuclear Energy Institute. October 2008.

NRC. "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." ML081140105. Washington, DC: U.S. Nuclear Regulatory Commission. June 2008.

_____. "Final Safety Evaluation for Electric Power Research Institute (EPRI) Report No. 1009325, Revision 2, Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals." ML072970208. Washington, DC: U.S. Nuclear Regulatory Commission. August 2007.

_____. NRC Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program." Revision 0. ML003740058. Washington, DC: U.S. Nuclear Regulatory Commission, September 1995.

_____. NRC Information Notice 92-20, "Inadequate Local Leak Rate Testing." ML031200473. Washington, DC: U.S. Nuclear Regulatory Commission. March 1992.

XI.S5 MASONRY WALLS

Program Description

The U.S. Nuclear Regulatory Commission (NRC) Inspection and Enforcement Bulletin (IEB) 80-11, "Masonry Wall Design," and NRC Information Notice (IN) 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IEB 80-11," constitute an acceptable basis for a masonry wall aging management program (AMP). IEB 80-11 required (a) the identification of masonry walls in close proximity to or having attachments from safety-related systems or components and (b) 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 (a) deterioration of the masonry walls (e.g., new cracks not considered in the reevaluation), (b) physical plant changes such as installation of new safety-related systems or components in close proximity to masonry walls, or (c) reclassification of systems or components from nonsafety-related to safety-related, provided appropriate evaluation is performed to account for such occurrences.

Important elements in the evaluation of many masonry walls during the NRC IEB 80-11 program included (a) installation of steel edge supports to provide a sound technical basis for boundary conditions used in seismic analysis and (b) 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 (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 impact masonry wall intended function or potentially invalidate its evaluation basis are entered into the corrective action process for further analysis, repair, or replacement.

Since the issuance of NRC IEB 80-11 and NRC IN 87-67, the NRC promulgated 10 CFR 50.65, "Maintenance Rule." For SLR, masonry walls may be inspected as part of GALL-SLR Report AMP XI.S6 conducted for the Maintenance Rule, provided the 10 attributes 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. 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 as being managed 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 impact 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. Walls that are both unreinforced and unbraced are inspected every 3 years. Provisions exist for more frequent inspections in areas where significant loss of material, cracking, or other signs of degradation are observed to ensure 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. 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, are measured and assessed for trends. Degradation detected from monitoring is evaluated. 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) are assessed against the evaluation basis to confirm the degradation has not invalidated the original evaluation assumptions or impacted the capability to perform the intended functions. Further evaluation is conducted to determine if corrective action is required when the degradation is determined to impact the intended function of the wall or invalidate its evaluation basis. Safety-related equipment near or adjacent to masonry walls should be inspected to ensure the affected masonry walls are being properly managed for aging. Degraded conditions that 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 as conditions adverse to quality or significant conditions adverse to quality under those 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 corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this 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 repair or replacing the degraded wall.

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

confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

10. ***Operating Experience****:* Since 1980, masonry walls that perform an intended function have been systematically identified through licensee programs in response to NRC Inspection and Enforcement Bulletin (IEB) 80-11, NRC Generic Letter (GL) 87-02, and 10 CFR 50.48. NRC IN 87-67 documented lessons learned from the NRC IEB 80-11 program and provided recommendations for administrative controls and periodic inspection to ensure that the evaluation basis for each safety-significant masonry wall is maintained. NUREG–1522 documents instances of observed cracks and other deterioration of masonry-wall joints at nuclear power plants (NPPs). Whether conducted as a stand-alone program or as a part of structures monitoring, a masonry wall AMP that incorporates the recommendations delineated in NRC IN 87-67 should ensure 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.48, “Fire Protection.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 54.4, “Scope.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

NRC. NUREG–1522, “Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures.” ML06510407. Washington, DC: U.S. Nuclear Regulatory Commission. June 1995.

_____. NRC Information Notice 87-67, “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11.” Washington, DC: U.S. Nuclear Regulatory Commission. December 1987.

_____. NRC Generic Letter 87-02, “Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46.” ML031150371. Washington, DC: U.S. Nuclear Regulatory Commission. February 1987.

_____. NRC IE Bulletin 80-11, "Masonry Wall Design." Washington, DC: U.S. Nuclear Regulatory Commission. May 1980.

XI.S6 STRUCTURES MONITORING

Program Description

Implementation of structures monitoring under 10 CFR 50.65 (the Maintenance Rule) is addressed in the U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.160, and Nuclear Management and Resources Council (NUMARC) 93-01. These two documents and supplemental guidance herein provide guidance for development of licensee-specific programs to monitor the condition of structures and structural components within the scope of the license renewal rule, such that there is no loss of structure or structural component intended function.

The structures monitoring program consists primarily of periodic visual inspections by personnel qualified to monitor structures and components (SCs), including protective coatings, for applicable aging effects from degradation mechanisms, such as those described in the American Concrete Institute (ACI) Standards 349.3R, ACI 201.1R, and Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11. Visual inspections are supplemented with volumetric or surface examinations to detect stress corrosion cracking (SCC) in high-strength (actual measured yield strength greater than or equal to 150 thousand-pound per square inch [ksi] or greater than or equal to 1,034 MPa) structural bolts greater than 1 inch [25 mm] in diameter. Identified aging effects are evaluated by qualified personnel using criteria derived from industry codes and standards contained in the plant current licensing bases, including ACI 349.3R, ACI 318, SEI/ASCE 11, and the American Institute of Steel Construction (AISC) specifications, as applicable.

The program includes preventive actions 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 structures, 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” (GALL-SLR Report AMP XI.S1); “ASME Section XI, Subsection IWL” (GALL-SLR Report AMP XI.S2); “ASME Section XI, Subsection IWF” (GALL-SLR Report AMP XI.S3); “Masonry Walls” (GALL-SLR Report AMP XI.S5); and NRC RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” (GALL-SLR Report AMP XI.S7).

   Examples of structures, SCs, and commodities in the scope of the program are concrete and steel structures, structural bolting and high-strength structural bolting (actual measured yield strength greater than or equal to 150 ksi or greater than or equal to 1,034 MPa), 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. Associated coatings are also included 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 provided all the attributes 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 attributes of this program.

2. ***Preventive Action**:* The structures monitoring program is primarily a condition monitoring program; however, the program includes preventive actions to ensure structural bolting integrity, as discussed in Electric Power Research Institute (EPRI) documents (such as EPRI NP-5067 and TR-104213), American Society for Testing and Materials (ASTM) standards, and American Institute of Steel Construction (AISC) specifications, as applicable. The preventive actions emphasize proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. If the structural bolting consists of ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of Research Council for Structural Connection (RCSC) publication “Specification for Structural Joints Using High-Strength Bolts,” need to be used.

3. ***Parameters Monitored or Inspected**:* For each structure/aging effect combination, the specific parameters monitored or inspected depend on the particular structure, SC, or commodity. Parameters monitored or inspected are commensurate with industry codes, standards, and guidelines and also consider industry and plant-specific operating experience. ACI 349.3R and SEI/ASCE 11 provide an acceptable basis for selection of parameters to be monitored or inspected for concrete and steel structural elements and for steel liners, joints, coatings, and waterproofing membranes (if applicable).

For concrete structures, parameters monitored include loss of material, cracking, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation. Steel SCs are monitored for loss of material due to corrosion. Structural steel bracing and edge supports associated with masonry walls are inspected for deflection or distortion, loose bolts, loss of material due to corrosion, and coating degradation. Painted or coated areas are examined for evidence of flaking, blistering, cracking, peeling, delamination, discoloration, and other 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. High-strength structural bolts greater than 1 inch [25 mm] in diameter are monitored for stress corrosion cracking (SCC). However, ASTM A325 and ASTM A490 bolts (or equivalent) used in civil structures have not been shown to be prone to SCC. Therefore, SCC potential need not be evaluated for high-strength bolts of those classifications when used in civil structures.

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 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 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 high-strength structural bolting greater than 1 inch [25 mm] in diameter is supplemented with volumetric or surface examinations to detect cracking. Visual inspection of elastomeric elements is supplemented by tactile inspection to detect hardening if the intended function is suspect. 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. 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 with a frequency that can identify potential seasonal variations (e.g., quarterly or semiannually). Groundwater is sampled from a location that is representative of the groundwater in contact with structures within the scope of license renewal. Inspector qualifications should be consistent with industry guidelines and standards and guidelines for implementing the requirements of 10 CFR 50.65. Qualifications of inspection and evaluation personnel specified in ACI 349.3R are acceptable for inspection of concrete structures.

   Indications of groundwater infiltration or through-concrete leakage should lead to corrective actions. Corrective actions 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, corrective actions should include analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water.

   The program recommends the use of accepted nondestructive examination (NDE) techniques, when applicable, to supplement visual inspections.

   The structures monitoring program addresses detection of aging affects for inaccessible, below-grade concrete structural elements. For plants with nonaggressive ground water/soil (pH > 5.5, chlorides < 500 ppm, or sulfates <1,500 ppm), the program recommends: (a) evaluating the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examining representative samples of the exposed portions of the below grade concrete, when excavated for any reason.

   For plants with aggressive ground water/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 period of extended operation. The plant-specific AMP includes focused inspections of below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/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. Quantitative measurements and qualitative data are recorded and trended for all applicable parameters monitored or inspected, and the use of photographs or surveys is encouraged. 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 period of subsequent license renewal (SLR).

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. The criteria are derived from applicable codes and standards that include but are not limited to ACI 349.3R, ACI 318, SEI/ASCE 11, or the relevant AISC specifications and consider industry and plant operating experience. 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. For concrete, the quantitative acceptance criteria of ACI 349.3R are acceptable. Applicants who are not committed to ACI 349.3R and 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 and cracked high-strength bolts 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 (a) no indications of excessive loss of material due to corrosion or wear and (b) 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 on acceptance criteria to conclude that this program attribute is satisfied.

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

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

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

10. ***Operating Experience****:* NUREG–1522 documents the results of a survey sponsored in 1992 by the Office of Nuclear Reactor Regulation to obtain information on the types of distress in the concrete and steel SCs, the type of repairs performed, and the durability of the repairs. Licensees who responded to the survey reported cracking, scaling, and leaching of concrete structures. The degradation was attributed to drying shrinkage, freeze-thaw, and abrasion. The NUREG also describes the results of NRC staff inspections at six plants. The staff observed concrete degradation, corrosion of component support members and anchor bolts, cracks and other deterioration of masonry walls, and groundwater leakage and seepage into underground structures. Information Notice (IN) 2011-20 discusses an instance of groundwater infiltration leading to alkali-silica reaction degradation in below-grade concrete structures, while IN 2004-05 and IN 2006-13 discuss instances of through-wall water leakage from spent fuel pools. 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 are adequately managed during the 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 SLR.

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

10 CFR 54.4, “Scope.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

AISC. “AISC Specification for Steel Buildings.” Chicago, Illinois: American Institute of Steel Construction, Inc. 2005.

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

_____. ACI Standard 318, “Building Code Requirements for Reinforced Concrete and Commentary.” Farmington Hills, Michigan: American Concrete Institute. 1995.

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

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

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

_____. 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.

NEI. NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” Rev. 4A. ML11116A198. Nuclear Energy Institute. 2011.

NRC. NRC Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” ML1136100898. Revision 3. Washington, DC: U.S. Nuclear Regulatory Commission. 2012.

_____. NRC Information Notice 2011-20, “Concrete Degradation by Alkali-Silica Reaction.” Washington, DC: U.S. Nuclear Regulatory Commission. November 2011.

_____. NRC Information Notice 2006-13, “Groundwater Contamination due to Undetected Leakage of Radioactive Water.” Washington, DC: U.S. Nuclear Regulatory Commission. July 2006.

_____. NRC Information Notice 2004-05, “Spent Fuel Pool Leakage to Onsite Groundwater.” Washington, DC: U.S. Nuclear Regulatory Commission. March 2004.

_____. NRC Regulatory Guide 1.142, “Safety-Related Concrete Structures for Nuclear Power Plants (Other than Reactor Vessels and Containments).” Revision 2. ML013100274. Washington, DC: U.S. Nuclear Regulatory Commission. 1997.

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

_____. NRC Regulatory Guide 1.127, “Inspection of Water-Control Structures Associated With Nuclear Power Plants.” Revision 1. ML003739392. Washington, DC: U.S. Nuclear Regulatory Commission. 1978.

RCSC. “Specification for Structural Joints Using High-Strength Bolts.” Chicago, Illinois. Research Council on Structural Connections. 2009.

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" (GALL-SLR Report AMP XI.S6); however, details pertaining to water-control structures, as described herein, should be explicitly incorporated and identified in GALL-SLR Report AMP XI.S6 program attributes if this approach is taken.

Attributes 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 compatibility to 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, and high-strength structural bolting (actual measured yield strength greater than or equal to 150 kilo-pounds per square inch [150 ksi] or greater than or equal to 1,034 megapascals (MPa) 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. Associated coatings are also included 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 ensure structural bolting integrity, as discussed in Electric Power Research Institute (EPRI) documents (such as EPRI NP-5067 and TR-104213), American Society for Testing and Materials (ASTM) standards, and American Institute of Steel Construction (AISC) specifications, as applicable. The preventive actions emphasize proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. If the structural bolting consists of ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of Research Council for Structural Connections (RCSC) (publication "Specification for Structural Joints Using High-Strength Bolts" need to be used).

3. ***Parameters Monitored or Inspected**:* NRC RG 1.127 identifies parameters to be monitored and inspected for water-control structures.

   Parameters to be monitored and inspected for concrete structures are those described in American Concrete Institute (ACI) 201.1R and ACI 349.3R. These 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 evidence of flaking, blistering, cracking, peeling, delamination, discoloration, and other 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. High-strength (actual measured yield strength ≥ 150 ksi or 1,034 MPa) structural bolts greater than 1 inch [25 mm] in diameter are monitored for stress corrosion cracking (SCC), with the exception of ASTM A325 and ASTM A490 bolts (including equivalent twist-off type F1852 and F2280 bolts) used in civil structures, which have not shown to be prone to SCC.

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 licensed professional engineers experienced in the investigation, design, construction, and operation of these types of facilities. Qualifications of inspection and evaluation personnel specified in ACI 349.3R are acceptable for reinforced concrete water control structures. Visual inspections are primarily used to detect 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 to detect degradation of water-control structures before a loss of an intended function. 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 raw water and ground water chemistry with a frequency that can identify potential seasonal variations (e.g. quarterly or semiannually). Ground water is sampled from a location that is representative of the water in contact with structures within the scope of subsequent license renewal (SLR).

Visual inspection of high-strength (actual measured yield strength ≥ 150 ksi or 1,034 MPa) structural bolting greater than 1 inch [25 mm] in diameter is supplemented with volumetric or surface examinations to detect cracking.

The program addresses detection of aging affects for inaccessible, below-grade, and submerged concrete structural elements. For plants with nonaggressive raw water and ground water/soil (pH > 5.5, chlorides < 500 parts per million [ppm], or sulfates < 1,500 ppm), the program includes (a) evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below-grade concrete when excavated for any reason. Submerged concrete structures may be inspected during periods of low tide or when dewatered and accessible. Plant-specific justification is provided in the subsequent license renewal application (SLRA) 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 with aggressive raw water (pH < 5.5, chlorides > 500 ppm, or sulfates > 1,500 ppm) or groundwater/soil 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 aging during the subsequent period of extended operation. The plant-specific AMP includes inspections of below-grade, inaccessible structural elements exposed to aggressive raw water or ground water/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. Quantitative measurements and qualitative data are recorded and trended for all applicable parameters monitored or inspected, and the use of photographs or surveys is encouraged. 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.

6. ***Acceptance Criteria****:* "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R provide acceptance criteria (including quantitative criteria) for concrete and specifies criteria for further evaluation. Although not required, plant-specific acceptance criteria based on Chapter 5 of ACI 349.3R are acceptable. Acceptance criteria for earthen structures, such as canals and embankments, are consistent with programs falling within the regulatory jurisdiction of the FERC or the USACE. Loose bolts and nuts, cracked high-strength bolts, 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 (SEI/ ASCE) 11-99, "Guideline for Structural Condition Assessment of Existing Buildings," and those referenced in the plant's current licensing basis (CLB).

7. ***Corrective Actions****:* Results that do not meet the acceptance criteria are addressed as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related 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. 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 include analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water.

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

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

10. ***Operating Experience****:* Degradation of water-control structures has been detected, through NRC RG 1.127 programs, at a number of NPPs, and, in some cases, it has required remedial action. NRC NUREG–1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures" described 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

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

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

AISC. "AISC Specification for Steel Buildings." Chicago, Illinois: American Institute of Steel Construction, Inc. 2010.

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

EPRI. EPRI TR-104213, "Bolted Joint Maintenance & Application Guide." Palo Alto, California: Electric Power Research Institute. December 1995.

____. 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.

NRC. NUREG–1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures." ML06510407. Washington, DC: U.S. Nuclear Regulatory Commission. June 1995.

_____. NRC Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” ML12216A016. Washington, DC: U.S. Nuclear Regulatory Commission. 1993.

_____. NRC Regulatory Guide 1.127, “Inspection of Water-Control Structures Associated With Nuclear Power Plants.” ML003739392. Washington, DC: U.S. Nuclear Regulatory Commission. March 1978.

RCSC. “Specification for Structural Joints Using High-Strength Bolts.” Research Council on Structural Connections. December 2009.

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 ensure 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 serve 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 2, 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. American Society for Testing and Materials (ASTM) D 5163-08 and endorsed years of the standard in NRC RG 1.54 are acceptable and considered consistent with NUREG–1801. In addition, Electric Power Research Institute (EPRI) Report 1019157, Guidelines for Inspection and Maintenance of Safety-related Protective Coatings, provides additional information on the ASTM standard guidelines.

A comparable program for monitoring and maintaining protective coatings inside containment, developed in accordance with NRC RG 1.54, Revision 2, is acceptable as an aging management program (AMP) for license renewal.

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 (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWE (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 are adequate for license renewal.

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 2, 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****:* Regulatory Position C4 in NRC RG 1.54, Revision 1, states that “ASTM D 5163-96 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...” ASTM D 5163-96 has been superseded by ASTM D 5163-08. ASTM D 5163-08 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****:* ASTM D 5163-08, paragraph 6, defines the inspection frequency to be each refueling outage or during other major maintenance outages, as needed. 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 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 preinspection 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 postponed to future outages, but under surveillance in the interim period. The assessment 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 ensure post-accident operability of the ECCS.

6. ***Acceptance Criteria****:* ASTM D 5163-08, subparagraphs 10.2.1 through 10.2.6, 10.3, and 10.4, contains 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

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

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

10. ***Operating Experience***: NRC Information Notice (IN) 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 1, was issued in July 2000. Monitoring and maintenance of Service Level I coatings conducted in accordance with Regulatory Position C4 is expected to be an effective program for managing degradation of Service Level I coatings and, consequently, an effective means to manage 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, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

ASTM. ASTM D 5163-08, “Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants.” West Conshohocken, Pennsylvania*:* American Society for Testing and Materials. 2008.

_____. ASTM D 5163-05, “Guide for Establishing Procedures to Monitor the Performance of Coating Service Level I Coating Systems in an Operating Nuclear Power Plant.” West Conshohocken, Pennsylvania: American Society for Testing and Materials. 2005.

_____. ASTM D 5163-96, “Standard Guide for Establishing Procedures to Monitor the Performance of Safety Related Coatings in an Operating Nuclear Power Plant.” West Conshohocken, Pennsylvania: American Society for Testing and Materials. 1996.

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

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

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

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

_____. NRC 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.

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 10 CFR 50.49 are maintained consistent with the current licensing basis (CLB) through the subsequent period of extended operation.

In most areas within a nuclear power plant (NPP), 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 where 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 cable and connectors. Electrical insulation used in electrical cables and connections may degrade more rapidly than expected when exposed to an adverse localized environment. Cable or connection electrical insulation subjected to an adverse localized environment may increase the rate of aging of a component or have an adverse effect on operability.

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

- 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 walk-downs 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; (a) directly applying the plant data in the evaluation, or (b) 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 also provided, as applicable, on the applicability of methodologies utilizing data that is collected and evaluated one time, or is of limited duration.

This AMP specifically addresses cables and connection electrical insulation at plants whose configuration is such that most (if not all) cables and connections including cable and connections identified as subjected to an adverse localized environment are accessible.

Accessible in-scope cables and connection from accessible areas are visually inspected for cable and connection degradation. In-scope cable and connection electrical insulation is also tested (e.g., testing comprised of one or more tests utilizing 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 including cable and connection electrical insulation identified as subject to an adverse localized environment.

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 (e.g., conduits), panels, terminal boxes, and junction boxes) to assess cable and connector electrical insulation aging degradation.

This AMP, as noted, is a cable and connection electrical insulation condition monitoring program that utilizes sampling. The visual inspection portion of the AMP uses accessible cable and connection electrical insulation visual inspection as representative of inaccessible cable and connection electrical insulation subject to the same environment.

The cable condition monitoring portion of the AMP utilizes component sampling for cable and connection electrical insulation testing. The following factors are considered in the development of the electrical insulation sample: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, and connection type, location (high temperature, high humidity, vibration, etc.) and the electrical insulation composition. The component sampling methodology utilizes a population that includes a representative sample of in-scope electrical cable and connection types regardless of whether or not the component was included in a previous aging management or maintenance program. The technical basis for the sample selections is documented.

Electrical insulation material for cables and connectors 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 aging management. If an unacceptable condition or situation is identified for cable or connection electrical insulation by visual inspection or test, corrective action is taken including a determination as to whether the same condition or situation is applicable to other in-scope accessible and inaccessible cable or connection electrical insulation (e.g., extent of condition). As such, this program does not apply to plants in which most cables are inaccessible.

As stated in NUREG/CR–5643, “the major concern is that failures of deteriorated cable systems (cables, connection electrical insulation) might be induced during accident conditions.” Since the cable and connection electrical insulation is not subject to the EA requirements of 10 CFR 50.49, an AMP is needed to manage the aging mechanisms and effects for the subsequent period of extended operation. This AMP provides reasonable assurance that the 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 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 is visually inspected for cable and connection insulation surface anomalies including identification of in-scope cable and connection electrical insulation subject to an adverse localized environment. The cable insulation visual inspection portion of the AMP uses the cable or connection jacket material as representative of the aging effects experienced by the cable and connector electrical insulation. In-scope cable and connection electrical insulation evaluated for signs of reduced electrical insulation resistance due to an adverse localized environment of temperature, moisture, radiation and oxygen that includes radiolysis, photolysis (UV sensitive materials only) of organics, radiation induced oxidation, moisture intrusion, or contamination (e.g., chemical, oil, or solvents) 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 there basis. The applicant reviews plant specific operating experience for the period of extended operation 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), for accessible cables and connections that are within the scope of license renewal.

4. ***Detection of Aging Effects****:* Aging effects resulting from temperature, radiation, or moisture causes surface abnormalities in the cable jacket, and connection material. Accessible electrical cables and connections are tested for reduced electrical insulation resistance and visually inspected for cable jacket and connection electrical insulation surface anomalies such as embrittlement, discoloration, cracking, melting, swelling or surface contamination. Cable and connection electrical insulation are inspected to identify cable and connection insulation installed in an adverse localized environment. Plant specific operating experience is also evaluated to identify in-scope cable and connection insulation previously subjected to adverse localized environment during the period of extended operation. Cable and connection insulation is evaluated to confirm

that the dispositioned corrective actions continue to support in-scope cable and connection intended functions during the subsequent period of extended operation.

The inspection and testing 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 found in the performance of this AMP or previously subjected to an adverse localized environment are visually inspected and tested at least once every 10 years. This is an adequate period to preclude failures of the cables and connection electrical insulation since experience has shown that aging degradation is a slow process. The first inspection and test for SLR is to be completed prior to the subsequent period of extended operation. Cable jacket and connection insulation are inspected and tested at least once prior to the subsequent period of extended operation. Visual inspection and testing may include thermography and one or more proven condition monitoring test methods applicable to the cable and connection insulation.

This AMP, as noted, is a cable and connection electrical insulation condition monitoring program that utilizes sampling. 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, and connection type, location (high temperature, high humidity, vibration, etc.) insulation material. The component sampling methodology utilizes a population that includes a representative sample of in-scope electrical cable and connection types regardless of whether or not 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 utilizing visual inspection and test results that are trendable provide additional information on 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 visual indications of surface abnormalities that indicate 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

Unacceptable test results and visual indications of cable and connection electrical insulation abnormalities are subject to an engineering evaluation. Such an evaluation considers the age and operating environment of the component as well as the severity of the abnormality and whether such an abnormality has previously been correlated to degradation of cable or connection insulation. Corrective actions include, but are not limited to, testing, shielding, or otherwise mitigating the environment or relocation or replacement of the affected cables or connections. When an unacceptable condition or situation is identified, a determination is made as to 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 those specific portions of the QA program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the confirmation process element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

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

10. ***Operating Experience****:* Industry operating experience 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 process 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.

    This AMP considers the technical information and guidance provided in NUREG/CR–5643, IEEE Std. 1205-2014, SAND96-0344, EPRI TR-109619, NUREG/CR–7000, IN 2010-25, IN 2010-26, 2010-2, RG 1.218, Generic Letter 2007-01, IEEE Std.422-2012 and IEEE Std. 576-2000.

    The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL-SLR Report.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments." Palo Alto, California: Electric Power Research Institute. June 1999.

IEEE. IEEE 422-2012, “Guide for the Design and Installation of Cable Systems in Power Generating Stations.” New York, New York: Institute of Electrical and Electronic Engineers. 2012.

_____. IEEE Std. 1205-2000, “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. 2000.

_____. IEEE 576-2000 “Recommended Practice for Installation, Termination, and Testing of Insulated Power Cable as Used in Industrial and Commercial Applications.” New York, New York: Institute of Electrical and Electronics Engineers. 2000.

NRC. Regulatory Guide 1.218, “Condition-Monitoring Techniques for Electric Cables Used In Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. April 2012.

_____. NRC Information Notice 2010-26, “Submerged Electrical Cables.” Washington, DC: U.S. Nuclear Regulatory Commission. December 2010.

_____. NRC Information Notice 2010-25, “Inadequate Electrical Connections.” Washington, DC: U.S. Nuclear Regulatory Commission. November 2010.

_____. NRC Information Notice 2010-2, “Construction Related Experience With Cables Connectors, and Junction Boxes.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2010.

_____. NUREG/CR–7000, “Essential Elements of an Electric Cable Condition Monitoring Program.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2010.

_____. Generic Letter 2007-01, “Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients.” Washington, DC: U.S. Nuclear Regulatory Commission. February 7, 2007.

_____. NUREG/CR-5643, “Insights Gained From Aging Research.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1992.

SNL. SAND96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants-Electrical Cable and Terminations.” Albuquerque, New Mexico: Sandia National Laboratories. September 1996.

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 10 CFR 50.49 and are used in instrumentation circuits with sensitive, high-voltage, low-level current signals) are maintained consistent with the current licensing basis (CLB) through the subsequent period of extended operation.

In most areas within a nuclear power plant (NPP) 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 where the operating environment is significantly more severe than the plant design basis environment. An adverse localized environment is based on the most limiting environment (e.g., temperature, radiation, or moisture) for the cable or connection insulation.

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

Adverse localized environments are identified through the use of an integrated approach. This approach includes, but is not limited to; (a) the review of EQ program radiation levels, temperature, and moisture information, (b) recorded information from equipment or plant instrumentation, (c) as-built and field walk down data (e.g., cable routing data base) (d) a plant spaces scoping and screening methodology, (e) the review of relevant plant-specific and industry operating experience including;

- 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 service life (current operating term)
- Previous walk downs including visual Inspection of accessible cable and connection electrical insulation
- Environmental monitoring e.g., periodic environmental monitoring – temperature, radiation or moisture)

Exposure of electrical insulation to adverse localized environments caused by temperature, radiation, or moisture can result 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 with sensitive, high voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation circuits, because a reduced insulation resistance (IR) may contribute to signal inaccuracies.

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

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

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

Evaluation and Technical Basis

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

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

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

4. ***Detection of Aging Effects****:* Review of calibration results or findings of surveillance programs can provide an indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. By reviewing the results obtained during normal calibration or surveillance, an applicant may detect severe aging degradation prior to the loss of the cable and connection intended function. 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 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 proven cable system test for detecting deterioration of the electrical insulation system (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition as justified in the application) is performed. 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 on the rate of cable or connection degradation.

6. ***Acceptance Criteria****:* 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

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

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

10. ***Operating Experience**:* The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, consistent with the discussion in Appendix B of the GALL-SLR Report.

Operating experience 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.

This AMP considers the technical information and guidance provided in EPRI TR-109619, EPRI TR-110379, EPRI TR-112582, IEEE Std. 1205- 2014, NRC IN 93-33, NUREG/CR–5643, NUREG/CR–5772, NUREG/CR–5461, and RG 1.218.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. EPRI TR-112582, “High Range Radiation Monitor Cable Study: Phase 2.” Palo Alto, California: Electric Power Research Institute. May 2000.

_____. EPRI TR-109619, “Guideline for the Management of Adverse Localized Equipment Environments, Palo Alto, California: Electric Power Research Institute. June 1999.

_____. EPRI TR-110379, “High Range Radiation Monitor Cable Study: Phase 1.” Palo Alto, California: Electric Power Research Institute. November 1998.

IEEE. IEEE Std. 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.

NRC. NRC Regulatory Guide 1.218, “Condition Monitoring Techniques for Electric Cables Used in Nuclear Power Plants.” Washington, DC: U.S, Nuclear Regulatory Commission. April 2012.

_____. NRC Information Notice 97-45, “Environmental Qualification Deficiency for Cables and Containment Penetration Pigtails.” Supplement 1. Washington, DC: U. S, Nuclear Regulatory Commission. February 1998.

_____. NRC Information Notice 97-45, “Environmental Qualification Deficiency for Cables and Containment Penetration Pigtails.” Washington, DC: U. S, Nuclear Regulatory Commission. July 1997.

_____. NRC Information Notice 93-33: “Potential Deficiency of Certain Class IE Instrumentation and Control Cables.” Washington, DC: U.S, Nuclear Regulatory Commission. April 1993.

_____. NUREG/CR–5772, “Aging, Condition Monitoring and Loss-of-Coolant Accident (LOCA) Tests of Class IE Electrical Cables Vol. 1 and 2.” Washington, DC: U.S, Nuclear Regulatory Commission. August 1992 October 1992.

_____. NUREG/CR–5643, “Insights Gained From Aging Research.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1992.

_____. NUREG/CR–5461, “Aging of Cables, Connections, and Electrical Penetrations Assemblies Used In Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. July 1990.

SNL. SAND96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants-Electrical Cable and Terminations.” Albuquerque, New Mexico: Sandia National Laboratories. September 1996.

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 the aging management program (AMP) is to provide reasonable assurance that the intended functions of inaccessible power cables (operating voltages of 2kV to 35kV) that are not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 are maintained consistent with the current licensing basis (CLB) through the subsequent period of extended operation. This AMP applies to all inaccessible or below grade (e.g., direct buried, buried conduit, duct bank, embedded raceway, cable trench, vaults, or manholes) medium voltage cable (operating voltages of 2kV to 35kV) within the scope of subsequent license renewal (SLR) exposed to adverse localized environments primarily due to significant moisture.

In most areas within a nuclear power plant (NPP), the actual operating environment (e.g., temperature, radiation, or moisture) is less severe than the anticipated 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 anticipated plant design basis environment (e.g., temperature, radiation, or moisture) for the cable and applicable connection electrical insulation.

Most electrical cables in NPPs are located in dry environments. However, some cables are inaccessible or below grade, 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 cables (and associated connections) are exposed to wetting, submergence, or other adverse localized environment conditions for which it was not designed, an accelerated aging effect of reduced insulation resistance may occur, causing a decrease in the dielectric strength of the electrical insulation.

Inaccessible medium voltage power cable electrical insulation may degrade more rapidly than expected when exposed to an adverse localized environment. Electrical insulation subjected to an adverse localized environment could increase the rate of aging of a component; have an adverse effect on operability, or potentially lead to failure of the cable.

Adverse localized environments are identified through the use of an integrated approach. This approach includes, but is not limited to; (a) the review of EQ zone program radiation, temperature and moisture information for various plant areas as applicable to inaccessible medium voltage power cable, (b) recorded information from equipment or plant instrumentation (e.g., applicable periodic environmental monitoring of in-scope inaccessible medium voltage cable installations), (c) as-built and field walk down data (e.g., cable routing data base), (d) a plant spaces scoping and screening methodology, and (e) the review of relevant plant-specific and industry operating experience including:

(a) Identification of work practices, including work records that have the potential to subject in-scope inaccessible medium voltage power cable to an adverse localized environment (e.g., equipment thermal insulation removal and restoration).

(b) Corrective actions involving for scope inaccessible medium voltage electrical insulation aging degradation on electrical insulation service life (current operating term).

(c) Previous inspections (e.g., cable vaults, and manholes) for medium voltage cable electrical insulation aging degradation associated with cable wetting and submergence.

In this AMP, 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 a few days (i.e., long term wetting or submergence over a continuous period). Cable wetting or submergence that occurs for a limited time as drainage occurs by either automatic or passive drains is not considered an adverse localized environment for this AMP.

The inspection frequency for water collection is established and performed based on plant-specific operating experience over time with cable wetting or submergence. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the subsequent period of extended operation. Inspection frequencies are adjusted based on inspection results including plant specific operating experience but with a minimum inspection frequency of at least once annually. Inspections are also performed after event driven occurrences, such as heavy rain, thawing of ice and snow, or flooding.

Examples of periodic actions to prevent inaccessible medium voltage cable exposure to significant moisture include inspection for water collection in cable manholes and conduits and draining water, as needed. However, these periodic actions may not be sufficient to ensure that water is not trapped elsewhere in the raceways. For example, water accumulation and submergence could occur from, (a) a duct bank conduit with low points in the routing; (b) raceways settling or cracking due to soil settling over a long period of time; (c) manhole covers not being watertight; (d) raceway locations subject to a high water table (e.g., high seasonal cycles); and (e) uncertainties exist concerning wetting and submergence even when duct banks are sloped with the intention to minimize water accumulation.

Experience has shown that insulation degradation may occur if the cables are exposed to continuous wetting or submergence. Although variances 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.

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 (e.g., identify degradation due to reduced electrical insulation resistance). The specific type of test considered is to be a proven technique for detecting deterioration of the cable insulation system (e.g., test is applicable to the specific cable construction: shielded and nonshielded and the insulation material under test). Tests may include combinations of situ or laboratory; electrical, physical, or chemical testing. Testing may include inspection and testing of cables or testing of coupons or abandoned or removed cables subjected to the same environment and exposed to the same or bounding inservice environment.

One or more tests may be required per cable construction and electrical insulation material, to determine the condition of the cable and that in-scope inaccessible medium voltage cable will continue to meet its intended function during the subsequent period of extended operation. 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 as part of this AMP.

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 power cables exposed to significant moisture, test frequencies are adjusted based on test results (including trending of aging degradation where applicable) and plant specific operating experience but with a minimum test frequency of at least once every 6 years.

As stated in NUREG/CR–5643, "the major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions." Because the cables are not subject to the environmental qualification requirements of 10 CFR 50.49, 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 period of extended operation.

Evaluation and Technical Basis

1. ***Scope of Program****:* This AMP applies to inaccessible or below grade medium voltage (operating voltages of 2kV to 35kV) power cable installations (e.g., direct buried, buried conduit, duct bank, embedded raceway, cable trench, vaults, or manholes) within the scope of license renewal exposed to adverse localized environments primarily due to significant moisture.

   Significant moisture is defined as exposure to moisture that lasts more than a few days (i.e., long term wetting or submergence over a continuous period). Cable wetting or submergence that occurs for a limited time as demonstrated by either automatic or passive drainage is not considered an adverse localized environment 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 onetime inspection with additional periodic test and inspections determined by the onetime test/inspection results and industry and plant specific aging degradation operating experience with the applicable cable electrical insulation.

2. ***Preventive Actions****:* This is a condition monitoring program. However, periodic actions are taken to prevent inaccessible medium 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 collection, and draining the water, as needed.

   The inspection frequency for water collection is established and performed based on plant-specific operating experience with cable wetting or submergence. The inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the subsequent period of extended operation. The annual inspection frequency is consistent with inspection procedure 71111.06.

   Inspections are also performed after event driven occurrences, such as heavy rain, thawing of ice and snow, or flooding. 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 are effective in preventing cable exposure to significant moisture or cables are not found submerged when water is manually pumped from manholes or vaults.

If water is found during inspection (i.e., cable exposed to significant moisture), corrective actions are taken to keep the cable dry and to assess cable degradation (i.e., through inspection and additional cable testing). The aging management of the physical structure, including cable support structures of cable vaults/manholes is managed by Generic Aging Lessons Learned Subsequent License Renewal (GALL-SLR) Report AMP XI.S6.

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

Inaccessible or below grade inaccessible medium voltage power cables within the scope of license renewal exposed to significant moisture are also tested to determine the condition of the electrical insulation. The specific type of test to be used is a proven technique capable of detecting reduced insulation resistance of the cable's insulation system due to wetting or submergence.

4. ***Detection of Aging Effects****:* 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 operating experience. 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 following tests performed at least once every 6 years thereafter. This is an adequate period to monitor performance of the cable and take appropriate corrective actions since experience has shown that although a slow process, aging degradation could be significant.

The specific type of test performed is determined prior to the initial test, and is to be a proven test for detecting aging degradation of the cable electrical insulation system (e.g., selected test is applicable to the specific cable construction: shielded and nonshielded, and the insulation material under test). Tests may include combinations of situ or laboratory electrical, physical, or chemical testing. Testing may include inspection and testing of cables or testing of coupons or abandoned or removed cables subjected to the same environment and exposed to the same or bounding inservice environment. A plant specific inaccessible medium voltage cable test matrix is developed to document inspections, test methods, and acceptance criteria applicable to in-scope inaccessible medium voltage cable for each cable type (e.g., electrical insulation, shielded/nonshielded, or fabrication.

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 cable test and inspection results, utilizing the same visual inspection and test methods that are trendable and repeatable, provide additional information on the rate of cable or connection insulation degradation.

6. ***Acceptance Criteria**:* The acceptance criteria for each test or inspection are defined 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 verified.

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

   Unacceptable test results and visual indications of electrical insulation material 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 electrical insulation. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to additional in-scope accessible and inaccessible cables or connections (extent of condition).

   Corrective actions may include, but are not limited to, installation of permanent drainage systems, (e.g., sump pumps, passive drainage systems and alarms), more frequent cable testing or inspections, repair (e.g., replace degraded cable sections with splices accessible), replacement of the affected cable, and root cause assessment of cable failures assessments, including forensic evaluations, with the AMP enhanced as necessary consistent with the discussion in Appendix B of the GALL-SLR Report.

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

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

10. ***Operating Experience**:* Operating experience has shown that electrical insulation materials undergo accelerated degradation either through water tree formation or due to other aging mechanisms when subjected to significant moisture. Inaccessible medium voltage cable subjected to significant moisture may result in an accelerated decrease in

the dielectric strength of the conductor electrical insulation. Minimizing exposure to moisture mitigates the potential for the development of reduced insulation resistance.

The U.S. Nuclear Regulatory Commission (NRC) issued Generic Letter (GL) 2007-001 concerning inaccessible or below grade cables to (a) inform licensees that the failure of certain power cables can affect the functionality of multiple accident mitigation systems or cause plant transients and (b) gather information from licensees on the monitoring of inaccessible or below grade power cable failures for all cables that are within the scope of the Maintenance Rule. The data obtained from the GL responses show an increasing trend of cable failures. The GL 2007-01 summary report noted that the predominant factor contributing to cable failures at nuclear power plants was due to moisture intrusion/submergence. These cables were failing within the plants' 40-year initial operating period.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience consistent with the discussion in Appendix B of the GALL-SLR Report.

This AMP considers the technical information and generic communication guidance provided in RG 1.218, NUREG/CR–5643; IEEE Std. 1205-2014; EPRI 109619; EPRI 103834-P1-2; NRC IN 2002-12; NRC IN 2010-26: NRC IN 1986-49; NRC GL 2007-01; NRC GL 2007-01 Summary Report; NRC Inspection Procedure, Attachment 71111.06, NRC Inspection Procedure, Attachment 71111.01; RG 1.211, RG 1.218; and NUREG/CR–7000.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments." Palo Alto, California: Electric Power Research Institute. June 1999.

IEEE. IEEE Std. 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.

NRC. NRC Inspection Manual, Attachment 71111.06, "Flood Protection Measures." Washington, DC: U.S. Nuclear Regulatory Commission. June 2012.

_____. Regulatory Guide 1.218, "Condition Monitoring Techniques for Electric Cables Used in Nuclear Power Plants." Revision 0. Washington, DC: U.S. Nuclear Regulatory Commission. April 2012.

_____. NRC Information Notice 2010-26, "Submerged Electrical Cables." Washington, DC: U.S. Nuclear Regulatory Commission. December 2010.

_____. NUREG/CR–7000, "Essential Elements of an Electric Cable Condition Monitoring Program." Washington, DC: U.S. Nuclear Regulatory Commission. January 2010.

_____. Regulatory Guide 1.211, “Qualification of Safety-Related Cables and Field Splices for Nuclear Power Plants.” Rev 0. Washington, DC: U.S. Nuclear Regulatory Commission. April 2009.

_____. NRC Inspection Manual, Attachment 71111.01, “Adverse Weather Protection.” Washington, DC: U.S. Nuclear Regulatory Commission. April 2009.

_____. NRC Generic Letter 2007-01, “Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients.” Summary Report. Washington, DC: U.S. Nuclear Regulatory Commission. November 12, 2008.

_____. NRC Information Notice 2002-12, “Submerged Safety-Related Electrical Cables.” Washington, DC: U.S. Nuclear Regulatory Commission. March 2002.

_____. NRC Information Notice 1986-49, “Age/Environment Induces Electrical Cable Failures.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1986.

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 the aging management program (AMP) is to provide reasonable assurance that the intended functions of inaccessible or below grade instrument and control cables that are not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 are maintained consistent with the current licensing basis (CLB) through the subsequent period of extended operation. This AMP applies to all inaccessible or below grade (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) instrumentation and control cable within the scope of subsequent license renewal (SLR) exposed to adverse localized environments primarily due to significant moisture.

In most areas within a nuclear power plant (NPP), the actual operating environment (e.g., temperature, radiation, or moisture) is less severe than the anticipated 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 anticipated plant design basis environment. An adverse localized environment is based on the most limiting environment (e.g., temperature, radiation, or moisture) for the cable applicable connections electrical insulation (e.g., splice).

Most electrical cables in NPPs are located in dry environments. However, some cables are inaccessible or below grade, cables 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 electrical cable is exposed to wetting, submergence, or other adverse localized environments for which it was not designed, an aging effect of reduced electrical insulation resistance may occur, causing a decrease in the dielectric strength of the conductor electrical insulation. If so equipped, the degradation of the cable shield due to water intrusion may introduce electrical grounds and noise into the circuit.

Inaccessible instrumentation and control cable electrical insulation including shields as applicable may degrade more rapidly than expected when exposed to an adverse localized environment. Electrical insulation subjected to an adverse localized environment could have an adverse effect on operability, or potentially lead to failure of the cable. Although the risk contribution due to a failure of an inaccessible instrument and control cable is limited due to system architecture, a common aging stressor such as submergence may represent a common aging mechanism that if not anticipated in the design or mitigated in service, may lead to multiple random failures and compromise system defense-in-depth and diversity.

Adverse localized environments are identified through the use of an integrated approach. This approach includes, but is not limited to; (a) the review of EQ program radiation, temperature and moisture information for various plant areas as applicable to inaccessible instrumentation and control cable, (b) recorded information from equipment or plant instrumentation (e.g., applicable periodic environmental monitoring of in-scope inaccessible instrumentation and control cable installations), (c) as-built and field walk down data (e.g., cable routing data base), (d) a plant spaces scoping and screening methodology, and (d) the review of relevant plant-specific and industry operating experience including;

- Identification of work practices, including work records that have the potential to subject in-scope inaccessible instrumentation and control cable to an adverse localized environment (e.g., equipment thermal insulation removal and restoration).
- Corrective actions involving in-scope inaccessible instrumentation and control electrical insulation aging degradation on electrical insulation service life (current operating term).
- Previous inspections (e.g., cable vaults, and manholes) for instrumentation and control cable electrical insulation aging degradation associated with cable wetting and submergence.

In this AMP, periodic actions are taken to prevent inaccessible instrumentation and control cables from being exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than a few days (i.e., long term wetting or submergence over a continuous period). Cable wetting or submergence that occurs for a limited time as demonstrated by either automatic or passive drains is not considered an adverse localized environment for this AMP.

The inspection frequency for water collection is established and performed based on plant-specific operating experience over time with cable wetting or submergence. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the subsequent period of extended operation. Inspection frequencies are adjusted based on inspection results including plant specific operating experience but with a minimum inspection frequency of at least once annually. Inspections are also performed after event driven occurrences, such as heavy rain, thawing of ice and snow, or flooding.

Examples of periodic actions to prevent inaccessible instrumentation and control cable exposure to significant moisture include inspection for water collection in cable manholes, vaults, and conduits and draining water, as needed. However, these periodic actions may not be sufficient to ensure that water is not trapped elsewhere in the raceways. For example water accumulation and submergence could occur from, (a) a duct bank conduit with low points in the routing; (b) raceway settling or cracking due to soil settling over a long period of time; (c) manhole and cable trench covers not being watertight; (d) raceway locations subject to a high water table (e.g., high seasonal cycles), and (e) uncertainties concerning wetting and submergence even when duct banks are sloped with the intention to minimize water accumulation.

Although aging mechanisms and effects due to significant moisture appear limited compared with inaccessible medium voltage cable (e.g., lower instrument and control voltage levels do not support water tree formation for example), operating experience has shown that insulation degradation may occur if inaccessible instrumentation and control cables are exposed to continuous wetting or submergence. Although variances may exist in the aging mechanisms and effects depending on electrical insulation material, manufacture, and application, periodic actions are necessary to minimize the potential for insulation degradation due to significant moisture.

In addition to the above periodic actions, in-scope inaccessible instrumentation and control cables exposed to significant moisture are tested to determine the condition of the electrical insulation (e.g., identify degradation due to reduced electrical insulation resistance). The specific type of test considered is to be a proven technique for detecting deterioration of the cable insulation system (e.g., test is applicable to the specific cable construction: shielded and nonshielded and the electrical insulation under test). Tests may include combinations of *in-situ* or laboratory, electrical, physical, or chemical testing. Testing may include inspection and testing of cables or testing of coupons or abandoned or removed cables subjected to the same environment and exposed to the same or bounding inservice environment.

For a large installed number of inaccessible instrumentation and control cable, a sample test methodology may be employed. A technical justification of the methodology and sample size used for selecting inaccessible instrumentation and control cables under test is included as part of the applicant's AMP's basis documentation. Inaccessible instrument and control cable factors are considered for sampling (e.g., voltage level, cable construction, cable type, insulation material, and location). If an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other inaccessible instrumentation and control cable not tested and whether the tested sample population should be expanded.

One or more tests may be required per cable construction and electrical insulation material to determine the condition of the cable and that in-scope inaccessible instrumentation and control cable will continue to meet its intended function during the subsequent period of extended operation. A plant specific inaccessible instrumentation and control cable test matrix that documents inspection methods, test methods, and acceptance criteria is developed as part of this AMP.

The first tests for SLR 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 instrumentation and control cables exposed to significant moisture, test frequencies are adjusted based on test results (including trending of aging degradation where applicable) and plant specific operating experience but with a minimum test frequency of at least once every 6 years.

As stated in NUREG/CR–5643, "the major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions." Because the cables are not subject to the EQ requirements of 10 CFR 50.49, 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 period of extended operation.

Evaluation and Technical Basis

1. ***Scope of Program****:* This AMP applies to all inaccessible or below grade (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) instrumentation and control cable within the scope of subsequent license renewal exposed to adverse localized environments primarily due to significant moisture.

   Significant moisture is defined as exposure to moisture that lasts more than a few days (i.e., long term wetting or submergence over a continuous period). Cable wetting or submergence that occurs for a limited time as demonstrated by either automatic or passive drainage is not considered an adverse localized environment for this AMP.

In-scope inaccessible 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 are also included in this AMP as a onetime inspection with additional periodic tests and inspections determined by the test/inspection results and industry and plant specific aging degradation operating experience with the applicable cable electrical insulation.

2. ***Preventive Actions****:* 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 collection, and draining the water, as needed.

The inspection frequency for water collection is established and performed based on plant-specific operating experience with cable wetting or submergence. The inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the subsequent period of extended operation. The annual inspection frequency is consistent with inspection procedure 71111.06.

Inspections are performed after event driven occurrences, such as heavy rain, thawing of ice and snow, or flooding. 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.

If water is found during inspection (i.e., cable exposed to significant moisture), corrective actions are taken to keep the cable dry and to assess cable degradation (i.e., through inspection and additional cable testing). The aging management of the physical structure, including cable support structures, of cable vaults/manholes is managed by Generic Aging Lessons Learned for Subsequent Licensing Renewal (GALL SLR) Report AMP XI.S6.

3. ***Parameters Monitored or Inspected****:* Inspection for water collection is performed based on plant-specific operating experience with water accumulation over time. Inaccessible or below grade instrumentation and control cables within the scope of SLR exposed to significant moisture are tested to determine the condition of the conductor electrical insulation. The specific type of test(s) to be used is a proven technique capable of detecting reduced insulation resistance of the cable's insulation system due to wetting or submergence.

4. ***Detection of Aging Effects****:* For inaccessible instrumentation and control cables exposed to significant moisture, test frequencies are adjusted based on test results (including trending of degradation where applicable) and plant specific operating

experience. Cable testing occurs at least once every 6 years. The first tests for SLR are to be completed prior to the subsequent period of extended operation with tests performed at least once every 6 years thereafter. This is an adequate period to monitor performance of the cable and take appropriate corrective actions since experience has shown that although a slow process, but that aging degradation could be significant.

The specific type of test performed is determined prior to the initial test, and is to be a proven test for detecting aging degradation of the cable insulation system (e.g., the selected test is applicable to the specific cable construction: shielded and nonshielded, and the insulation material under test). Tests may include combinations of *in-situ* or laboratory, electrical, physical, or chemical testing. Testing may include inspection and testing of cables or testing of coupons or abandoned or removed cables subjected to the same environment and exposed to the same or bounding inservice environment. A plant specific instrumentation and control test matrix is developed to document inspections, test methods, and acceptance criteria applicable to the applicant's in-scope inaccessible instrumentation and control cable for each type (e.g., electrical insulation, shielded/nonshielded, or fabrication).

For a large installed number of inaccessible instrumentation and control cable, a sample test methodology may be employed. A technical justification of the methodology and sample size used for selecting inaccessible instrumentation and control cables under test should be included as part of the applicant's AMP's basis documentation. Inaccessible instrument and control cable factors are considered for sampling (e.g., voltage level, cable construction, cable type, insulation material, and location). If an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other inaccessible instrumentation and control cable not tested and whether the tested sample population should be expanded. The corrective action program is used to evaluate the condition and determine appropriate corrective action.

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 cable test and inspection results utilizing the same visual inspection and test methods that are trendable and repeatable provide additional information on the rate of cable or connection insulation degradation.

6. ***Acceptance Criteria**:*   The acceptance criteria for each test or inspection are defined 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 verified.

7. ***Corrective Actions**:* Results that do not meet the acceptance criteria are addressed as conditions adverse to quality or significant conditions adverse to quality under those 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 corrective actions element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

Unacceptable test results and visual indications of electrical insulation material 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 electrical insulation. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to additional in-scope accessible and inaccessible cables or connections (extent of condition).

Corrective actions may include, but are not limited to, installation of permanent drainage systems, (e.g., sump pumps, passive drainage systems and alarms), more frequent cable testing or inspections, repair (e.g., replace degraded cable sections), replacement of the affected cable, and root cause assessment of cable failures including forensic evaluations as applicable, with the AMP enhanced as necessary consistent with the discussion in Appendix B of the GALL-SLR Report.

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

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

10. ***Operating Experience****:* Operating experience has shown that electrical insulation materials undergo accelerated degradation either through water tree formation or due to other aging mechanisms when subjected to significant moisture. Inaccessible instrumentation and control cable subjected to significant moisture may result in an accelerated decrease in the dielectric strength of the conductor electrical insulation. Minimizing exposure to significant moisture mitigates the potential for the development of reduced insulation resistance and, if so equipped, the degradation of the cable shield due to water intrusion which may introduce unwanted grounds and noise into the circuit.

    The U.S. Nuclear Regulatory Commission (NRC) issued Generic Letter (GL) 2007-001 concerning inaccessible or below grade cables to (a) inform licensees that the failure of certain power cables can affect the functionality of multiple accident mitigation systems or cause plant transients and (b) gather information from licensees on the monitoring of inaccessible or below grade power cable failures for all cables that are within the scope of the Maintenance Rule. The data obtained from the GL responses show an increasing trend of cable failures. The GL 2007-01 summary report noted that the predominant factor contributing to cable failures at NPPs was due to moisture intrusion/submergence. These cables were failing within the plants’ 40-year initial licensing period.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating consistent with the discussion in Appendix B of the GALL-SLR Report.

This AMP considers the technical information and generic communication guidance provided in RG 1.218, NUREG/CR–5643; IEEE Std. 1205-2014; EPRI 109619; EPRI 103834-P1-2; NRC IN 2002-12; NRC IN 2010-26: NRC IN 1986-49; NRC GL 2007-01; NRC GL 2007-01 Summary Report; NRC Inspection Procedure, Attachment 71111.06, NRC Inspection Procedure, Attachment 71111.01; RG 1.211, RG 1.218; and NUREG/CR–7000.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. EPRI TR-109619, “Guideline for the Management of Adverse Localized Equipment Environments.” Palo Alto, California: Electric Power Research Institute. June 1999.

IEEE. IEEE Std. 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.

NRC. Regulatory Guide 1.218, “Condition Monitoring Techniques for Electric Cables Used in Nuclear Power Plants.” Revision 0. Washington, DC: U.S. Nuclear Regulatory Commission. April 2012.

_____. NRC Information Notice 2010-26, “Submerged Electrical Cables.” Washington, DC: U.S. Nuclear Regulatory Commission. December 2010.

_____. NUREG/CR–7000, “Essential Elements of an Electric Cable Condition Monitoring Program.” Washington, DC: U.S. Nuclear Regulatory Commission. January 2010.

_____. NRC Inspection Manual, Attachment 71111.06, “Flood Protection Measures.” Washington, DC: U.S. Nuclear Regulatory Commission. June 2009.

_____. NRC Inspection Manual, Attachment 71111.01, “Adverse Weather Protection.” Washington, DC: U.S. Nuclear Regulatory Commission. April 2009.

_____. Regulatory Guide 1.211, “Qualification of Safety-Related Cables and Field Splices for Nuclear Power Plants.” Revision 0. Washington, DC: U.S. Nuclear Regulatory Commission. April 2009.

_____. NRC Generic Letter 2007-01, “Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients.” Summary Report. Washington, DC: U.S. Nuclear Regulatory Commission. November 2008.

_____. NRC Information Notice 2002-12, “Submerged Safety-Related Electrical Cables.” Washington, DC: U.S. Nuclear Regulatory Commission. March 2002.

_____. NRC Information Notice 1986-49, “Age/Environment Induces Electrical Cable Failures.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1986.

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 the aging management program (AMP) is to provide reasonable assurance that the intended functions of inaccessible or below grade low voltage power cables (i.e., typical operating voltage of less than 1,000v–but no greater than 2kV) that are not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 are maintained consistent with the current licensing basis (CLB) through the subsequent period of extended operation. This AMP applies to all inaccessible or below grade (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) low voltage power cable within the scope of subsequent license renewal (SLR) exposed to adverse localized environments primarily due to significant moisture.

In most areas within a nuclear power plant (NPP), the actual operating environment (e.g., temperature, radiation, or moisture) is less severe than the anticipated 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 anticipated plant design basis environment (e.g., temperature, radiation, or moisture) for the cable electrical insulation.

Most electrical cables in NPPs are located in dry environments. However, some cables are inaccessible or below grade, cables 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 electrical cable is exposed to wetting, submergence, or other adverse localized environments for which it was not designed, an aging effect of reduced electrical insulation resistance may occur causing a decrease in the dielectric strength of the conductor electrical insulation. Therefore, this AMP considers inaccessible low voltage power cable exposed to wetting or submergence or other adverse localized environments for which the cable was not designed, as potentially subject to an aging effect of reduced insulation resistance causing a decrease in the dielectric strength of the conductor electrical insulation.

Inaccessible low voltage power cable electrical insulation may degrade more rapidly than expected when exposed to an adverse localized environment. Electrical insulation subjected to an adverse localized environment could have an adverse effect on operability, or potentially lead to failure of the cable’s insulation system.

Adverse localized environments are identified through the use of an integrated approach. This approach includes, but is not limited to; (a) the review of EQ program radiation, temperature and moisture information for various plant areas as applicable to inaccessible low voltage power cable, (b) recorded information from equipment or plant instrumentation (e.g., applicable periodic environmental monitoring of in-scope inaccessible low voltage power cable installations), (c) as-built and field walk down data (e.g., cable routing data base), (d) a plant spaces scoping and screening methodology, and (d) the review of relevant plant-specific and industry operating experience including;

- Identification of work practices, including work records that have the potential to subject in-scope inaccessible low voltage power cable to an adverse localized environment (e.g., equipment thermal insulation removal and restoration).

- Corrective actions involving in-scope inaccessible low voltage power cable electrical insulation aging degradation on electrical insulation service life (current operating term).

- Previous inspections (e.g., cable vaults, and manholes) for inaccessible low voltage cable electrical insulation aging degradation associated with cable wetting and submergence.

In this AMP, periodic actions are taken to prevent inaccessible low voltage power cables from being exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than a few days (i.e., long term wetting or submergence over a continuous period). Cable wetting or submergence that occurs for a limited time as demonstrated by either automatic or passive drains is not considered an adverse localized environment for this AMP.

The inspection frequency for water collection is established and performed based on plant-specific operating experience over time with cable wetting or submergence. The inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least annually with the first inspection for SLR completed prior to the subsequent period of extended operation. Inspection frequencies are adjusted based on inspection results including plant specific operating experience but with a minimum inspection frequency of at least annually. Inspections are also performed after event driven occurrences, such as heavy rain, thawing of ice and snow, or flooding.

Examples of periodic actions are inspecting for water collection in cable manholes, vaults, and conduits and draining water, as needed. However, the periodic actions may not be sufficient to ensure that water is not trapped elsewhere in the raceways. For example, (a) if a duct bank conduit has low points in the routing, there could be potential for continuous submergence at these low points; (b) raceways may settle or crack due to soil settling over a long period of time; (c) manhole and cable trench covers may not be watertight; (d) raceway locations subject to a high water table (e.g., high seasonal cycles); and (e) uncertainties concerning wetting and submergence even when duct banks are sloped with the intention to minimize water accumulation.

Although specific aging mechanisms and effects due to significant moisture are not documented for low voltage power cable and the voltage levels are considered low enough not to support water tree formation. Operating experience suggests that insulation degradation may occur if inaccessible low voltage power cables are exposed to continuous wetting or submergence. Although variances may exist in the aging mechanisms and effects depending on cable electrical insulation material, manufacture, and application, periodic actions are necessary to minimize the potential for insulation degradation due to significant moisture.

In addition to the above periodic actions, in-scope inaccessible low voltage power cables exposed to significant moisture are tested to determine the condition of the electrical insulation (e.g., identify degradation due to reduced electrical insulation resistance). The specific type of test considered is to be a proven technique for detecting deterioration of the cable insulation system (e.g., test is applicable to the specific cable construction and electrical insulation under test). Tests may include combinations of *in-situ* or laboratory, electrical, physical, or chemical testing. Testing may include inspection and testing of cables or testing of coupons or abandoned or removed cables subjected to the same environment and exposed to the same or bounding inservice environment. One or more tests, as required per cable construction and insulation material, are used to determine the condition of the cable and ensure that in-scope inaccessible low voltage power cables will continue to meet their intended function during the subsequent period of extended operation. A plant specific inaccessible low voltage power cable test matrix that documents inspection methods, test methods, and acceptance criteria is developed as part of this AMP.

The first tests for SLR 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 low 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 operating experience but with a minimum test frequency of at least once every 6 years.

As stated in NUREG/CR–5643, “the major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions.” Because the cables are not subject to the EQ requirements of 10 CFR 50.49, 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 period of extended operation.

Evaluation and Technical Basis

1. ***Scope of Program**:* This AMP applies to all inaccessible or below grade (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) low voltage power cable within the scope of SLR exposed to adverse localized environments primarily due to significant moisture.

   Significant moisture is defined as exposure to moisture that lasts more than a few days (i.e., long term wetting or submergence over a continuous period). Cable wetting or submergence that occurs for a limited time as demonstrated by either automatic or passive drainage is not considered an adverse localized environment for this AMP.

   In-scope inaccessible 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 are also included in this AMP as a onetime inspection with additional periodic test and inspections determined by the test/inspection results and industry and plant specific aging degradation operating experience with the applicable cable electrical insulation.

2. ***Preventive Actions**:* 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 collection, and draining the water, as needed.

   The inspection frequency for water collection is established and performed based on plant-specific operating experience with cable wetting or submergence. The inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the subsequent period of extended operation. The annual inspection frequency is consistent with inspection procedure 71111.06.

Inspections are performed after event driven occurrences, such as heavy rain, thawing of ice and snow, or flooding. 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.

If water is found during inspection (i.e., cable exposed to significant moisture), corrective actions are taken to keep the cable dry and to assess cable degradation (i.e., through inspection and cable testing). The aging management of the physical structure, including cable support structures, of cable vaults/manholes is managed by Generic Aging Lessons Learned for Subsequent Licensing Renewal (GALL-SLR) Report AMP XI.S6.

3. ***Parameters Monitored or Inspected**:* Inspection for water collection is performed based on plant-specific operating experience with water accumulation over time. Inaccessible or below grade low voltage power cables within the scope of SLR exposed to significant moisture are tested to determine the condition of the electrical conductor insulation. The specific type of test(s) to be used is a proven technique capable of detecting reduced insulation resistance of the cable's insulation system due to wetting or submergence.

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

   The specific type of test performed is determined prior to the initial test, and is to be a proven test for detecting aging degradation of the cable electrical insulation system (e.g., the selected test is applicable to the specific cable construction: shielded and nonshielded, and the insulation material under test).

   Tests may include combinations of *in-situ* or laboratory; electrical, physical, or chemical testing. Testing may include inspection and testing of cables or testing of coupons or abandoned or removed cables subjected to the same environment and exposed to the same or bounding inservice environment. A plant specific inaccessible low voltage test matrix is developed to document inspections, test methods, and acceptance criteria applicable to the applicant's in-scope inaccessible low voltage power cable types.

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 cable test and inspection results utilizing the same visual inspection and test methods that are

trendable and repeatable provide additional information on the rate of cable or connection insulation degradation.

6. ***Acceptance Criteria**:* The acceptance criteria for each test or inspection are defined by the specific type of test performed and the specific cable tested. Acceptance criteria for inspections of manholes are defined by the direct indication that cable support structures are intact and cables are not submerged. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected and their operation verified.

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

   Corrective actions may include, but are not limited to, installation of permanent drainage systems, (e.g., sump pumps, passive drainage systems and alarms), more frequent cable testing or inspections, repair (e.g., replace degraded cable sections), replacement of the affected cable, and root cause assessment of cable failures including forensic evaluations as applicable, with the AMP enhanced as necessary consistent with the discussion in Appendix B of the GALL-SLR Report.

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

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

10. ***Operating Experience**:* Operating experience has shown that electrical insulation materials are susceptible water intrusion failures including water tree formation. Aging effects of reduced insulation resistance due to other aging mechanisms and effects may also result in a decrease in the dielectric strength of the conductor insulation. Minimizing exposure to moisture mitigates the potential for the development of reduced insulation resistance.

    The U.S. Nuclear Regulatory Commission (NRC) issued Generic Letter (GL) 2007-001 concerning inaccessible or below grade cables to (a) inform licensees that the failure of certain power cables can affect the functionality of multiple accident mitigation systems or cause plant transients and (b) gather information from licensees on the monitoring of inaccessible or below grade power cable failures for all cables that are within the scope of the Maintenance Rule. The data obtained from the GL responses show an increasing trend of cable failures. The GL 2007-01 summary report noted that the predominant factor contributing to cable failures at NPPs was due to moisture intrusion/submergence. These cables are failing within the plants' 40-year initial licensing period.

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

This AMP considers the technical information and generic communication guidance provided in RG 1.218, NUREG/CR–5643; IEEE Std. 1205-2014; EPRI 109619; EPRI 103834-P1-2; NRC IN 2002-12; NRC IN 2010-26: NRC IN 1986-49; NRC GL 2007-01; NRC GL 2007-01 Summary Report; NRC Inspection Procedure, Attachment 71111.06, NRC Inspection Procedure, Attachment 71111.01; RG 1.211, RG 1.218; and NUREG/CR–7000.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments." Palo Alto, California: Electric Power Research Institute. June 1999.

IEEE. IEEE Std. 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.

NRC. Regulatory Guide 1.218, "Condition Monitoring Techniques for Electric Cables Used in Nuclear Power Plants." Revision 0. Washington, DC: U.S. Nuclear Regulatory Commission. April 2012.

_____. NRC Information Notice 2010-26, "Submerged Electrical Cables." Washington, DC: U.S. Nuclear Regulatory Commission. December 2010.

_____. NUREG/CR–7000, "Essential Elements of an Electric Cable Condition Monitoring Program." Washington, DC: U.S. Nuclear Regulatory Commission. January 2010.

_____. NRC Inspection Manual, Attachment 71111.06, "Flood Protection Measures." Washington, DC: U.S. Nuclear Regulatory Commission. June 2009.

_____. NRC Inspection Manual, Attachment 71111.01, "Adverse Weather Protection." Washington, DC: U.S. Nuclear Regulatory Commission. April 2009.

_____. Regulatory Guide 1.211 "Qualification of Safety-Related Cables and Field Splices for Nuclear Power Plants." Revision 0. Washington, DC: U.S. Nuclear Regulatory Commission. April 2009.

_____. NRC Generic Letter 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients." Summary Report. Washington, DC: U.S. Nuclear Regulatory Commission. November 2008.

_____. NRC Information Notice 2002-12, “Submerged Safety-Related Electrical Cables.” Washington, DC: U.S. Nuclear Regulatory Commission. March 2002.

_____. NRC Information Notice 1986-49, “Age/Environment Induces Electrical Cable Failures.” Washington, DC: U.S. Nuclear Regulatory Commission. June 1986.

SNL. SAND96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants-Electrical Cable and Terminations.” Albuquerque, New Mexico: Sandia National Laboratories. September 1996.

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 bus (MEB) 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.

Cable bus is a variation on MEB which is similar in construction to an MEB, but instead of segregated or nonsegregated electrical buses, cable bus is comprised of a fully enclosed metal enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus may omit the top cover or use a louvered top cover and enclosure. Both the cable bus and enclosures are not sealed against intrusion of dust, industrial pollution, moisture, rain, ice and therefore may introduce debris into the internal cable bus assembly.

Consequently, cable bus construction and arrangements are such that it may not readily fall under a specific Generic Aging Lessons Learned (GALL) Report AMP (e.g., GALL-SLR Report AMP XI.E1, GALL-SLR Report AMP XI.E4, or GALL-SLR Report AMP XI.E6). GALL-SLR Report AMP XI.E1 calls for a visual inspection of accessible insulated cables and connections subject to an adverse localized environment which may not be applicable to cable bus due to inaccessibility or applicability of the aging mechanisms and effects addressed by GALL-SLR Report AMP XI.E1. GALL-SLR Report AMP XI.E4 includes tests and inspections of the internal and external portions of the MEB. The MEB Internal and external inspections and tests may not be entirely applicable to cable bus aging mechanisms and effects. GALL-SLR Report AMP XI.E6 applies to the metallic parts of cable connections at equipment termination points. As a result, cable bus due to its construction, constitutes a component with possible aging mechanisms and effects that may not be addressed by GALL-SLR Report AMP XI.E6. Therefore, the GALL-SLR Report recommends cable bus aging mechanisms and effects be evaluated as a plant specific further evaluation including further evaluation of a plant specific AMP and any associated AMPs (e.g., GALL-SLR Report AMP XI.S6, “Structures Monitoring,” XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” and GALL-SLR Report AMP XI.S6, “Structures Monitoring”) as applicable.

Industry operating experience 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 bus work 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, SAND 96-0344 identified instances of termination loosening at several plants due to thermal cycling and NRC Information Notice (IN) 2000-14 identified torque relaxation of splice plate connecting bolts as one potential cause of MEB failures.

This AMP includes the inspection of all bus duct and 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 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 portions of MEB enclosure assemblies can be managed under GALL-SLR Report AMP XI.S6, “Structures Monitoring.”

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, indicate overheating or aging degradation. The internal bus insulating supports are inspected for structural integrity and signs of cracks. Bolted connections are inspected for increased resistance of connection (e.g., loose or corroded MEB bolted connections and hardware including cracked or split washers). Alternatively, 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 and 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 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 operating experience) that the inaccessible MEB segments evaluation, together with the accessible MEB inspection and test program, will continue to maintain the MEB consistent with the current licensing basis 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 and loss of strength.

   Bolted connections are inspected for increased resistance of connection by using thermography or by measuring connection resistance using a micro ohmmeter. When thermography is employed by the applicant, the applicant demonstrates with a documented evaluation that 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 is completed prior to the subsequent period of extended operation and every 10 years thereafter. This is an adequate period to preclude failures of the MEBs since experience has shown that MEB aging degradation is a slow process.

   As an alternative to 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 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 on the rate of degradation.

6. ***Acceptance Criteria****:* MEB electrical insulation materials are free from regional indications of surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, and swelling, or surface contamination. MEB internal surfaces show no indications of corrosion, cracks, foreign debris, excessive dust buildup, or evidence of moisture intrusion. Accessible elastomers (e.g., gaskets, boots, and sealants) show no indications of surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning”

and “necking”), shrinkage, discoloration, hardening, and loss of strength. MEB external surfaces are free from 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. 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.

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.

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

   Corrective actions are taken and an engineering evaluation is performed when the acceptance criteria are not met. Corrective actions 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 ensure that the MEB intended function can be maintained consistent with the CLB. The engineering evaluation considers the significance of the calibration, surveillance, inspection or test results; the operability of the component; the report ability of the event; 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 as to 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 as to whether the surveillance, inspection, or test, including frequency intervals, needs to be modified.

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

9. ***Administrative Controls****:* Administrative controls are addressed through the QA program that is used to meet the requirements of 10 CFR Part 50, Appendix B,

associated with managing the effects of aging. Appendix A of the GALL-SLR Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the administrative controls element of this AMP for both safety-related and nonsafety-related SCs within the scope of this program.

10. ***Operating Experience**:* The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, consistent with as discussed in Appendix B of the GALL-SLR Report.

    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.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. "Switchgear and Bus Maintenance Guide." Palo Alto, California: Electric Power Research Institute, Nuclear Maintenance Application Center. December 2006.

_____. "Cable System Management." Palo Alto, California: Electric Power Research Institute. 2002.

_____. "Electrical Connector Application Guidelines." Palo Alto, California: Electric Power Research Institute. December 2002

_____. "Infrared Thermography Guide." Palo Alto, California: Electric Power Research Institute. 2002.

_____. "Plant Support Engineering: License Renewal Electrical Handbook." Palo Alto, California: Electric Power Research Institute. 2001.

IAEA. Ageing Management for Nuclear Power Plants." Safety Guide No. NS-G-2.12, IAEA. Vienna: International Atomic Energy Agency. February 2009.

IEEE. IEEE Std. 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.

NRC. NRC Information Notice 2010-25, "Inadequate Electrical Connections." Washington, DC: U.S. Nuclear Regulatory Commission. November 2010.

_____. NRC Information Notice 2000-14, "Non-Vital Bus Fault Leads to Fire and Loss of Offsite Power." Washington, DC: U.S. Nuclear Regulatory Commission. September 2000.

_____. NRC Information Notice 98-36, "Inadequate or Poorly Controlled, Non-Safety-Related Maintenance Activities Unnecessary Challenged Safety Systems." Washington, DC: U.S. Nuclear Regulatory Commission. September 1998.

_____. NUREG/CR-5461, "Aging of Cables, Connections, and Electrical Penetration Assemblies Used in Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. July 1990.

_____. NRC Information Notice 89-64, "Electrical Bus Bar Failures." Washington, DC: U.S. Nuclear Regulatory Commission. September 1989.

XI.E5 FUSE HOLDERS

Program Description

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

Fuse holders (fuse blocks) are classified as a specialized type of terminal block because of the similarity in 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, are either (a) spring-loaded clips which allow the fuse ferrules or (b) blades to slip in and be held in place, bolt lugs, to which the fuse ends are bolted.

The scope of GALL-SLR Report AMP XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," includes cable and connection electrical insulation material but not the metallic portion of cables and connections. This AMP inspects both the fuse holder electrical insulation material and the metallic portion of the fuse holder (metallic clamps).

Industry operating experience has shown that repetitive removal and reinsertion of fuses during maintenance or surveillance activities can lead to degradation of the fuse holders. Fuse holders where fuses are removed and replaced frequently for maintenance or surveillance activities are also included in this AMP to manage the aging effects of these repetitive activities.

The metallic portion of fuse holders that are within the scope of SLR and 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, and frequent removal and insertion, or vibration. 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, such as thermography, contact resistance testing, or other appropriate testing justified in the application.

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

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

Evaluation and Technical Basis

1. ***Scope of Program**:* This AMP manages the metallic portion (metallic clamps) of in-scope fuse holders that are 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. The electrical insulation portion of the fuse holder is visually inspected for electrical insulation surface abnormalities 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.

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 portion (metallic clamps) of the fuse holder is tested to provide an indication 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. 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 license renewal are visually inspected and tested at least once every 10 years to provide an indication of the condition of the fuse holder. Testing of the fuse holder metallic portion includes 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 on the rate of degradation.

6. ***Acceptance Criteria**:* 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 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 of 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   Corrective actions, such as recalibration and circuit trouble-shooting, are implemented when calibration, surveillance, cable or component inspection or test results do not meet the acceptance criteria. An engineering evaluation is performed when the acceptance criteria are not met in order to ensure that the intended functions of the electrical cable system can be maintained consistent with the current licensing basis. Such an evaluation is to consider the significance of the calibration, surveillance, or cable system inspection or test results; the operability of the component; the reportability of the event; the extent of the concern; the potential root causes for not meeting the acceptance criteria; the corrective actions required; and likelihood of recurrence. When an unacceptable condition or situation is identified, a determination is made as to whether the calibration, surveillance, inspection, or the cable system test frequency needs to be modified.

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

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

10. **Operating Experience**: The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, consistent with the discussion in Appendix B of the GALL-SLR Report.

Operating experience 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 indicate signs of reduced insulation resistance are aging mechanisms which if left unmanaged, can lead to a loss of electrical continuity function. NUREG–1760 documents fuse holder failures due to fatigue and recommends the review of maintenance procedures (e.g., fuse control programs) to minimize removal and reinsertion of fuses to de-energize components (as this can lead to degradation of the fuse holder assembly).

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

IEEE. IEEE Std. 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.

NRC. NUREG–1760*,* “Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. May 2002.

_____. NRC Information Notice 91-78, “Status Indication of Control Power for Circuit Breakers Used in Safety-Related Application.” Washington, DC: U.S. Nuclear Regulatory Commission. November 1991.

_____. NUREG–1760*,* “Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. May 2002. NRC Information Notice 87-42, “Diesel Generator Fuse Contacts.” Washington, DC: U.S. Nuclear Regulatory Commission. September 1987.

_____. NRC Information Notice 86-87, “Loss of Offsite Power Upon an Automatic Bus Transfer.” Washington, DC: U.S. Nuclear Regulatory Commission. October 1986.

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 requirements of 10 CFR 50.49 and susceptible to age-related degradation resulting in increased resistance of the connection 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 (CLB) 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 (NPPs) include bolted connectors, coaxial/triaxial connections, compression/crimped connectors, splices butt or bolted), stress cone, and terminal block. 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 ensure 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.

GALL-SLR Report AMP XI.E1, “Electrical Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” manages the aging of insulating material but not the metallic parts of the electrical connections and 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 of 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 impact 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.

Cable connections within the scope of license renewal are tested at least once every 10 years or at least once every 5 years if only visual inspection is used to provide an indication of the integrity of the cable connections. The first visual inspections and 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 for covered cable connections. The basis for performing only a periodic visual inspection is documented.

This AMP, as described, is a sampling program. The following factors are considered for sampling: voltage level (medium and low voltage), 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 as to 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 since they are already addressed by the requirements of 10 CFR 50.49. Even though cable connections may not be exposed to harsh environments, increased resistance of 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 kilovolts) switchyard connections. The cable connections covered under the environmental qualification (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. Periodic testing provides an indication of increased resistance of 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 voltage), 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 are tested prior to and during the SLR period of extended operation. Periodic testing of in scope connections manages the aging mechanisms and effects requiring management during the SLR period of extended operation. Testing

may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. Periodic testing provides additional confirmation to support industry operating experience 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.

A representative sample of electrical connections within the scope of license renewal will be tested at least once every 10 years. The first tests for license renewal are to be completed prior the SLR 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 SLR 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 on 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.

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

   Corrective actions, such as sample expansion, increased inspection frequency, and replacement or repair of the affected cable connection components are implemented when calibration, surveillance, or cable system inspection or test results do not meet the acceptance criteria. An engineering evaluation is performed when the acceptance criteria are not met in order to ensure that the intended functions of the electrical cable system can be maintained consistent with the CLB. Such an evaluation is to consider the significance of the calibration, surveillance, or cable system inspection or test results; the operability of the component; the reportability of the event; the extent of the concern; the potential root causes for not meeting the acceptance criteria; the corrective actions required; and likelihood of recurrence. When an unacceptable condition or situation is identified, a determination is also made as to whether the tested sample size calibration, surveillance, inspection, or the cable system test frequency needs to be modified.

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

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

10. ***Operating Experience***: The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, consistent with the discussion in Appendix B of the GALL-SLR Report.

    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. There have been limited numbers of age-related failures of cable connections reported. An applicant's operating experience with connection reliability and aging effects should be adequate to demonstrate the AMP effectiveness of GALL-SLR Report AMP XI.E6, "Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements " including the program's capability to detect the presence or noting the absence of aging effects for electrical cable connections.

    The program includes provisions for the continuous review of plant-specific and industry operating experience, including research and development results (for instance, aging prediction model development, new acceptability criteria, nondestructive test methods, etc.) such that the effectiveness of the program is evaluated and any necessary actions or modifications to the AMP are performed.

References

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants." Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

EPRI. EPRI 1003471, "Electrical Connector Application Guidelines." Palo Alto, California: Electric Power Research Institute. December 2002.

_____. EPRI 109619, “Guideline for the Management of Adverse Localized Equipment Environments.” Palo Alto, California: Electric Power Research Institute. June 1999.

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

IEEE. IEEE Std. 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.

Licensee Event Report 3612007005, “San Onofre Unit 2, Loose Electrical Connection Results in Inoperable Pump Room Cooler.” https://lersearch.inl.gov/LERSearchCriteria.aspx. 2009.

Licensee Event Report 3612007006, “San Onofre Units 2 and 3, Loose Electrical Connection Results in One Train of Emergency Chilled Water (ECW) System Inoperable.” https://lersearch.inl.gov/LERSearchCriteria.aspx. 2009.

Licensee Event Report 3612008006, “San Onofre 2, Loose Connection Bolting Results in Inoperable Battery and TS Violation.” https://lersearch.inl.gov/LERSearchCriteria.aspx. 2009.

NEI. NEI White Paper, “GALL-SLR AMP XI.E6 (Electrical Cables).” ML062770105. Washington, DC: Nuclear Energy Institute. September 2006.

_____. 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.” ML070400349. Washington DC: U.S. Nuclear Regulatory Commission. March 2007.

NRC. NUREG/CR-5643, “Insights Gained From Aging Research.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1992.

XI.E7 HIGH VOLTAGE INSULATORS

Program Description

The purpose of the 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 (CLB) through the subsequent period of extended operation. The high voltage insulator program was developed specifically to age manage high voltage insulators susceptible to adverse localized environments.

The High Voltage Insulators program includes visual inspections to identify insulation and metallic component degradation. Visual inspection provides reasonable assurance that the applicable aging effects are identified and high voltage insulator age degradation is managed. Insulation materials used in high voltage insulators may degrade more rapidly than expected in an adverse environment. The component parts of the insulator are made of porcelain, malleable iron, aluminum, galvanized steel, and cement. Loss of material due to mechanical wear or various airborne contaminates such as dust, salt, fog, cooling tower plume, and industrial effluent can contaminate the insulator surface leading to reduced insulation resistance. Surface rust in metallic parts may appear where galvanizing is worn. With significant airborne contamination such as salt, surface rust in metallic parts may become significant such that the insulator no longer will support the conductor. Excessive surface contaminates or loss of material can lead to insulator flashover.

The high-voltage insulators within the scope of this program are to be visually inspected at least twice per year. For high voltage insulators that are coated, the visual inspection is performed at least once every 5 years. 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 adverse environments are identified and high voltage insulator aging effects are age managed during the subsequent period of extended operation.

Evaluation and Technical Basis

1. ***Scope of Program***: This AMP manages the age related degradation effects of within scope high voltage insulators susceptible to airborne contaminants including dust, salt, fog, cooling tower plume, industrial effluent or loss of material. The high voltage insulators within the scope of the subsequent period of extended operation are those credited for recovery of offsite power.

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 prevent the buildup of contaminates on the insulator surface. The periodic coating or cleaning of high voltage insulators limits high voltage insulator surface contamination and may reduce the frequency of periodic visual inspection and cleaning depending on plant operating experience.

3. ***Parameters Monitored or Inspected***: The high-voltage insulators within the scope of this program are visually inspected at least twice per year. For high voltage insulators that are coated, the visual inspection is performed at least once every 5 years. This is an adequate period to detect aging effects before a loss of component intended function

occurs since operating experience has shown that high voltage insulator aging degradation is a slow process. High Voltage Insulator surfaces are visually inspected to detect reduced insulation resistance aging effects including cracks, foreign debris, and significant salt, dust, cooling tower plume and industrial effluent contamination. Metallic parts of the insulator are visually inspected to detect loss of material due to mechanical wear or corrosion.

4. ***Detection of Aging Effects***: Visual inspection is used to detect insulator loss of material and reduced insulation resistance due to presence of insulator surface contamination. Visual inspections may be supplemented with infrared thermography inspections to detect high voltage insulator reduced insulation resistance. 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 on the rate of insulator degradation including optimization of inspection frequencies.

6. ***Acceptance Criteria***: High voltage insulator surfaces are free of contamination such as significant salt or dust buildup or other contaminants. Metallic parts must be free of loss of materials due to pitting, crevice, and general corrosion. 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 as conditions adverse to quality or significant conditions adverse to quality under those specific portions of the quality assurance (QA) program that are used to meet Criterion XVI, “Corrective Action,” of 10 CFR Part 50, Appendix B. Appendix A of the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report describes how an applicant may apply its 10 CFR Part 50, Appendix B, QA program to fulfill the corrective actions element of this AMP for both safety-related and nonsafety-related structures and components (SCs) within the scope of this program.

   Corrective actions are taken and an engineering evaluation is performed when the acceptance criteria are not met. Corrective actions will be based on the observed degradation. The evaluation will consider 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 as to whether the same condition or situation is applicable to other high voltage insulators. Corrective actions will be implemented when inspection results do not meet the acceptance criteria.

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

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

10. ***Operating Experience***: The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, consistent with the discussion in Appendix B of the GALL-SLR Report.

    This AMP considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. 1205-2000, SAND96-0344, EPRI 1001997, EPRI 1013475, and EPRI TR-109619.

References

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants.” Washington, DC: U.S. Nuclear Regulatory Commission. 2015.

IEEE. IEEE Std. 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.

EPRI. EPRI 1013475, “Plant Support Engineering: License Renewal Electrical Handbook.” Revision 1. Palo Alto, California: Electric Power Research Institute. February 2007.

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

NRC. NRC Information Notice 93-95: “Storm-Related Loss of Offsite Power Events Due to Salt Buildup on Switchyard Insulators.” Washington, DC: U.S. Nuclear Regulatory Commission. 1993.

_____. NUREG/CR-5643, “Insights Gained From Aging Research.” Washington, DC: U.S. Nuclear Regulatory Commission. March 1992.

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	The program provides 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 requirements of 10 CFR 50.49 are maintained consistent with the current licensing basis through the subsequent period of extended operation. The program is a cable and connection insulation material condition monitoring program that utilizes sampling. The component sampling methodology utilizes a population that includes a representative sample of in-scope electrical cable and connection types regardless of whether or not the component was included in a previous aging management or maintenance program. The technical basis for the sample selection is documented. The program applies to accessible electrical cable and connection electrical insulation material within the scope of license renewal including in-scope cables and connections 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. 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. Visual inspection results show that accessible cable and connection insulation material are free from visual indications of surface	First inspection for license renewal completed prior to the subsequent period of extended operation	GALL VI / SRP 3.6

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		abnormalities that indicate cable or connection electrical insulation aging effects exist. When acceptance criteria are not met, a determination is made as to whether the surveillance, inspection, or tests, including frequency intervals, need to be modified. 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 (e.g., test methods, aging models, acceptance criterion) such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report. [The FSAR Summary description also includes a plant specific discussion of applicable commitments, license conditions, enhancements, or exceptions applied to the applicants aging management program]		
XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	The program applies to electrical cables and connections (cable system) electrical insulation material used in circuits with sensitive, high voltage, low-level current signals. 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 cable and connection subjected to an adverse localized environment. In addition to the evaluation and identification of adverse localized environments, either of two methods can be used to identify the existence of cable and	First review of calibration results or findings of surveillance test results or cable tests for license renewal completed prior to the subsequent period of extended operation	GALL VI / SRP 3.6

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		connection insulation material aging degradation. In the first method, calibration results or findings of surveillance testing programs are evaluated to identify the existence of electrical cable and connection insulation material aging degradation. In the second method, direct testing of the cable system is performed. By reviewing the results obtained during normal calibration or surveillance, an applicant may detect severe aging degradation prior to the loss of the cable and connection intended function. The review of calibration results or findings of surveillance tests is performed at least once every 10 years. 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. In cases where cables are not included as part of calibration or surveillance program testing circuit, a proven cable test shown to be effective in determining cable system electrical insulation condition as justified in the applicant's aging management program is performed. The first reviews and tests are completed prior to 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 (e.g., test methods, aging models, acceptance criterion) such that the effectiveness of the AMP is evaluated consistent with the discussion in		

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		Appendix B of the GALL-SLR Report. [The FSAR Summary description also includes a plant specific discussion of applicable commitments, license conditions, enhancements, or exceptions applied to the applicants aging management program]		
XI.E3A	Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements	The 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; 2.3kV to 35kv) within the scope of license renewal exposed to adverse localized environments due primarily to significant moisture. An adverse localized environment is based on the most limiting environment (e.g., temperature, radiation, or moisture) for the cable electrical insulation. Significant moisture is considered an adverse localized environment for these in scope inaccessible cables. The cables included in this program are not subject to the environmental qualification requirements of 10 CFR 50.49. Electrical insulation subjected to an adverse localized environment could increase the rate of aging of a component and therefore have an adverse effect on operability, or potentially lead to failure of the cable's insulation system. Although a condition monitoring program, periodic inspections are performed to prevent inaccessible	First tests or first inspections for subsequent license renewal completed prior to the subsequent period of extended operation	GALL VI / SRP 3.6

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		cable from being exposed to significant moisture. These inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least annually with the first inspection for subsequent license renewal completed prior to the subsequent period of extended operation. Inspections are performed after event driven occurrences, such as heavy rain, thawing of ice and snow, or flooding. Both the periodic and event driven 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 drains) and associated alarms are inspected and their operation verified. Inspections include documentation that either automatic or passive drainage systems, or manually pumping manholes and vaults is effective in preventing inaccessible cable submergence. Test frequencies are adjusted based on test results (including trending of degradation where applicable) and plant specific operating experience. The first tests for subsequent license renewal are to be completed prior to the subsequent period of extended operation with tests performed at least every 6 years thereafter. The specific type of test performed is determined prior to the initial test, and is to be a proven test for detecting deterioration of the cable insulation system (e.g., one or more tests may be required depending to the specific cable construction: shielded and non-shielded, and the		

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		insulation material under test). Tests may include combinations of situ or laboratory; electrical, physical, or chemical testing. Testing may include inspection and testing of cables or testing of coupons or abandoned or removed cables subjected to the same environment and exposed to the same or bounding inservice environment. A plant specific inaccessible medium voltage test matrix is developed to document inspections, test methods, and acceptance criteria applicable to the applicant's in-scope inaccessible medium voltage power cable types. [The FSAR Summary description also includes a plant specific discussion of applicable commitments, license conditions, enhancements, or exceptions applied to the applicants aging management program]		
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements	The 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 adverse localized environments due primarily to significant moisture. An adverse localized environment is based on the most limiting environment (e.g., temperature, radiation, or moisture) for the cable electrical insulation. Significant moisture is considered an adverse localized environment for these in scope inaccessible cables. The cables included in this	First tests or first inspections for subsequent cense renewal completed prior to the subsequent period of extended operation	GALL VI / SRP 3.6

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		program are not subject to the environmental qualification requirements of 10 CFR 50.49. Electrical insulation subjected to an adverse localized environment could increase the rate of aging of a component and therefore have an adverse effect on operability, or potentially lead to failure of the cable's insulation system. In scope inaccessible instrument and control cables submarine or other cables designed for continuous wetting or submergence are also included in this program as a onetime inspection with additional test and inspection frequencies determined by the onetime test, inspection results, and plant specific operating history Although a condition monitoring program, periodic inspections are performed to prevent inaccessible cable from being exposed to significant moisture. These inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least annually with the first inspection for subsequent license renewal completed prior to the subsequent period of extended operation. Inspections are performed after event driven occurrences, such as heavy rain, thawing of ice and snow, or flooding. Both the periodic and event driven 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 drains) and associated alarms are inspected and their operation verified. Inspections include		

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		documentation that either automatic or passive drainage systems, or manually pumping manholes and vaults is effective in preventing inaccessible cable submergence. Test frequencies are adjusted based on test results (including trending of degradation where applicable) and plant specific operating experience. The first tests for subsequent license renewal are to be completed prior to the subsequent period of extended operation with tests performed at least every 6 years thereafter. The specific type of test performed is determined prior to the initial test, and is to be a proven test for detecting deterioration of the cable insulation system (e.g., one or more tests may be required depending to the specific cable construction: shielded and non-shielded, and the insulation material under test). Tests may include combinations of situ or laboratory; electrical, physical, or chemical testing. Testing may include inspection and testing of cables or testing of coupons or abandoned or removed cables subjected to the same environment and exposed to the same or bounding inservice environment. For a large installed number of inaccessible instrumentation and control cables, a sample test methodology may be employed. A plant specific inaccessible instrument and control cables voltage test matrix is developed to document inspections, test methods, and acceptance criteria applicable to the applicant's in-scope inaccessible instrument and control cable types.		

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
XI.E3C	Electrical Insulation for Inaccessible Low Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements	The 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; 1000v – but less than 2kV) within the scope of license renewal exposed to adverse localized environments due primarily to significant moisture. An adverse localized environment is based on the most limiting environment (e.g., temperature, radiation, or moisture) for the cable electrical insulation. Significant moisture is considered an adverse localized environment for these in scope inaccessible cables. The cables included in this program are not subject to the environmental qualification requirements of 10 CFR 50.49. Electrical insulation subjected to an adverse localized environment could increase the rate of aging of a component and therefore have an adverse effect on operability, or potentially lead to failure of the cable's insulation system. In-scope inaccessible low voltage power cable splices subjected to wetting or submergence are also included within the scope of this program. In scope inaccessible low voltage submarine or other cables designed for continuous wetting or submergence are also included in this program as a onetime inspection with additional test and inspection frequencies determined by the onetime test, inspection results, and plant specific operating history Although a condition monitoring program, periodic inspections are performed to prevent inaccessible cable from being exposed to significant moisture. These inspections are performed periodically based on water	First tests or first inspections for license renewal completed prior to the subsequent period of extended operation	GALL VI / SRP 3.6

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		accumulation over time. The periodic inspection occurs at least annually with the first inspection for subsequent license renewal completed prior to the subsequent period of extended operation. Inspections are performed after event driven occurrences, such as heavy rain, thawing of ice and snow, or flooding. Both the periodic and event driven 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 drains) and associated alarms are inspected and their operation verified. Inspections include documentation that either automatic or passive drainage systems, or manually pumping manholes and vaults is effective in preventing inaccessible cable submergence. Test frequencies are adjusted based on test results (including trending of degradation where applicable) and plant specific operating experience. The first tests for subsequent license renewal are to be completed prior to the subsequent period of extended operation with tests performed at least every 6 years thereafter. The specific type of test performed is determined prior to the initial test, and is to be a proven test for detecting deterioration of the cable insulation system (e.g., one or more tests may be required depending to the specific cable construction: shielded and non-shielded, and the insulation material under test). Tests may include combinations of situ or laboratory, electrical, physical, or chemical testing. Testing may include inspection and testing of cables or testing of coupons or abandoned or removed cables subjected to the same environment and exposed to the same or bounding inservice environment. For a large installed number of		

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		inaccessible low voltage power cables, a sample test methodology may be employed. A plant specific inaccessible low voltage test matrix is developed to document inspections, test methods, and acceptance criteria applicable to the applicant's in-scope inaccessible low voltage power cable types.		
XI.E4	Metal Enclosed Bus	The program requires the visual inspection of metal enclosed bus (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, boots, 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. Bolted connections are inspected for increased resistance of connection by using thermography or by measuring connection resistance using a micro-ohmmeter. When thermography is employed by the applicant, the applicant demonstrates with a documented evaluation that thermography is effective in identifying MEB increased resistance of connection (e.g., infrared viewing windows installed, or demonstrated test equipment capability).	First inspection for subsequent license renewal completed prior to the subsequent period of extended operation	GALL VI / SRP 3.6

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		The first inspection using thermography or measuring connection resistance is completed prior to the subsequent period of extended operation and at least every 10 years thereafter. As an alternative to thermography or measuring connection resistance of accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., the applicant may use visual inspection of the electrical insulation to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. When 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. Cable bus is a variation on MEB with similar in construction to an MEB, but instead of segregated or non-segregated electrical buses, cable bus is comprised of a fully enclosed metal enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus may omit the top cover or use a louvered top cover and enclosure. Both cable bus enclosures are not sealed against the intrusion of dust, industrial pollution, moisture, rain, or ice and therefore may be allow debris into the internal cable bus assembly. Cable bus construction and arrangement are such that it does not readily fall under a specific GALL Report AMP (e.g., GALL-SLR Report AMP XI.E4 or GALL-SLRT Report AMP XI.E1). Therefore, cable bus is evaluated as a plant specific aging management program with a plant specific further evaluation. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-		

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		specific and industry operating experience including research and development (e.g., test methods, aging models, acceptance criterion) such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report. [The FSAR Summary description also includes a plant specific discussion of applicable commitments, license conditions, enhancements, or exceptions applied to the applicants aging management program]		
XI.E5	Fuse Holders	The program was developed to specifically address aging management of fuse holder insulation material and fuse holder metallic clamp aging mechanisms and effects. In scope fuse holders located inside an active device (e.g., switchgear, power supplies, power inverters, control boards, battery chargers) and subject to fatigue caused by frequent fuse removal and replacement (e.g., surveillance, functional testing, and calibration) are also within the scope of this AMP. The scope of GALL-SLR Report AMP XI.E1, “Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” includes cable and connection electrical insulation material but not the metallic portion of cables and connections. This AMP inspects both the fuse holder electrical insulation material and the metallic portion of the fuse holder (metallic clamps). The program utilizes visual inspection and testing to identify age-related degradation for both fuse holder electrical insulation material and fuse holder metallic clamps. The	First tests for subsequent license renewal completed prior to the subsequent period of extended operation	GALL VI / SRP 3.6

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		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 aging management program. Fuse holders within the scope of license renewal are visually inspected and tested at least once every 10 years to provide an indication of the condition of the fuse holder. The first visual inspections and tests for license renewal are to be completed prior to the subsequent period of extended operation. When acceptance criteria are not met, a determination is made as to whether the inspections, or tests, including frequency intervals, need to be modified. This 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 (e.g., test methods, aging models, acceptance criterion) such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report. [The FSAR Summary description also includes a plant specific discussion of applicable commitments, license conditions, enhancements, or exceptions applied to the applicants aging management program]		
XI.E6	Electrical Cable Connections Not Subject to 10 CFR	The program provides reasonable assurance that the metallic parts of electrical cable connections that are not subject to the environmental qualification requirements of	First tests for subsequent license renewal completed	GALL VI / SRP 3.6

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
	50.49 Environmental Qualification Requirements	10 CFR 50.49 and susceptible to age-related degradation resulting in increased resistance of the connection are adequately managed. External cable connections associated with in-scope cables that terminate 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. The cable connections covered under the Environmental Qualification (EQ) program are not included in the scope of this program. This AMP does not include high-voltage (>35 kilovolts) switchyard connections. This program is a sampling program. The following factors are considered for sampling: voltage level (medium and low voltage), 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 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	prior to the subsequent period of extended operation	

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		performing only a periodic visual inspection is documented. A representative sample of electrical connections within the scope of license renewal will be tested at least once every 10 years or at least once every 5 years if only visual inspection is used to provide an indication of the connection integrity. The first visual inspections and tests for license renewal are to be completed prior to the subsequent license renewal period of extended operation. This 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 (e.g., test methods, aging models, acceptance criterion) such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report. [The FSAR Summary description also includes a plant specific discussion of applicable commitments, license conditions, enhancements, or exceptions applied to the applicants aging management program]		
XI.E7	High Voltage Insulators New AMP	The program was developed specifically to address aging management of high voltage insulator aging mechanisms and effects. This AMP 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 high voltage insulators within the scope of the subsequent period of extended operation are those credited for recovery of offsite power.	New AMP	GALL VI / SRP 3.6

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		This program includes visual inspections to identify insulation and metallic component degradation. High voltage insulator surfaces are visually inspected to detect reduced insulation resistance aging effects including cracks, foreign debris, and excessive salt, dust, cooling tower plume and industrial effluent contamination. Metallic parts of the insulator are visually inspected to detect loss of material due to mechanical wear or corrosion. The high-voltage insulators within the scope of this program are to be visually inspected at least twice per year. For high voltage insulators that are coated, the visual inspection is performed at least once every 5 years. The first inspections for the subsequent period of extended operation are to be completed prior to the subsequent period of extended operation. This 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 (e.g., test methods, aging models, acceptance criterion) such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report. [The FSAR Summary description also includes a plant specific discussion of applicable commitments, license conditions, enhancements, or exceptions applied to the applicants aging management program]		
XI.M1	ASME Section XI Inservice Inspection,	The program consists of periodic volumetric, surface, and/or visual examination of American Society of Mechanical	SLR program is implemented prior to	GALL IV / SRP

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
	Subsections IWB, IWC, and IWD	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 during the period of extended operation.	the subsequent period of extended operation	3.1 GALL VII / SRP 3.3
XI.M2	Water Chemistry	This program mitigates 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 (a) BWRVIP-190 (EPRI 1016579, BWR Water Chemistry Guidelines – 2008 Revision) for BWRs or (b) EPRI 1014986 (PWR Primary Water Chemistry – Revision 6) and EPRI 1016555 (PWR Secondary Water Chemistry – Revision 7) for pressurized water reactors (PWRs).	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1
XI.M3	Reactor Head Closure Stud Bolting	The program includes (a) in-service inspection (ISI) in conformance with the requirements of the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, and (b) preventive measures to mitigate cracking. The program also relies on recommendations to address reactor head stud bolting degradation as delineated in NRC Regulatory Guide (RG) 1.65, Revision 1.	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
XI.M4	BWR Vessel ID Attachment Welds	The program is a condition monitoring program that manages cracking in the reactor vessel inside diameter attachment welds. This program relies on visual examinations to detect cracking. The examination scope, frequencies, and methods are in accordance with ASME Code, Section XI, Table-IWB-2500-1, Examination Category B-N-2, and BWRVIP-48-A, “Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines,” dated November 2004. The scope of the examinations is expanded when flaws are detected. Any indications are evaluated in accordance with ASME Code, Section XI, or the guidance in BWRVIP 48-A. Crack growth evaluations follow the guidance in BWRVIP-14-A, “Evaluation of Crack Growth in BWR Stainless Steel RPV Internals, dated September 2008; BWRVIP-59-A, “Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals,” dated May 2007; or BWRVIP-60-A, “BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals,” dated June 2003; as appropriate. The acceptance criteria are in BWRVIP-48-A and ASME Code, Section XI, Subsubarticle IWB-3520. Repair and replacement activities are conducted in accordance with BWRVIP-52-A, “Shroud Support and Vessel Bracket Repair Design Criteria,” dated September 2005.	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1
XI.M5	BWR Feedwater Nozzle	*Description for plants that do not have single sleeve interference fit feedwater spargers:* This program is a condition monitoring program that manages the effects of cracking in the reactor vessel feedwater nozzles. This program implements the guidance in GE-NE-523-A71-0594-A, Revision 1, “Alternate BWR	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		Feedwater Nozzle Inspection Requirements," dated May 2000. Cracking is detected through ultrasonic examinations of critical regions of the BWR feedwater nozzle, as depicted in Zones 1, 2, and 3 on ["Figure 4-1," if the nozzle is clad, or "Figure 4-2," if the nozzle is un-clad] of GE NE 523 A71-0594-A, Revision 1. The ultrasonic examination procedures, equipment, and personnel are qualified by performance demonstration in accordance with ASME Code, Section XI, Appendix VIII. The examination frequency for all three zones is once every 10-year ASME Code, Section XI, in-service inspection interval. Examination results are evaluated in accordance with ASME Code, Section XI, Subsection IWB-3130. *Description for plants that have single sleeve interference fit feedwater spargers:* This program is a condition monitoring program that manages the effects of cracking in the reactor vessel feedwater nozzles. This program implements the guidance in GE-NE-523-A71-0594-A, Revision 1, "Alternate BWR Feedwater Nozzle Inspection Requirements," dated May 2000. Cracking is detected through ultrasonic examinations of critical regions of the BWR feedwater nozzle, as depicted in Zones 1, 2, and 3 on ["Figure 4-1," if the nozzle is clad, or "Figure 4-2," if the nozzle is un-clad] of GE NE 523 A71-0594-A, Revision 1. The ultrasonic examination procedures, equipment, and personnel are qualified by performance demonstration in accordance with ASME Code, Section XI, Appendix VIII. The examination frequency for Zones 1 and 2 is once every [X] years, and the examination frequency for Zone 3 is once every [Y] years. Examination results are evaluated		

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		in accordance with ASME Code, Section XI, Subsection IWB-3130.		
XI.M7	BWR Stress Corrosion Cracking	The program manages cracking due to intergranular stress corrosion cracking (IGSCC) for all BWR piping and piping welds made of austenitic stainless steel and nickel alloy that are 4 inches or larger in nominal diameter containing reactor coolant at a temperature above 93 °C (200 °F) during power operation, regardless of code classification. The program performs volumetric examinations to detect and manage IGSCC in accordance with NRC Generic Letter (GL) 88-01. Modifications to the extent and schedule of inspection in GL 88-01 are allowed in accordance with the inspection guidance in staff-approved BWRVIP-75-A. This program relies on the staff-approved positions that are described in NUREG-0313, Revision 2, and GL 88-01 and its Supplement 1 regarding selection of IGSCC-resistant materials, solution heat treatment and stress improvement processes, water chemistry, weld overlay reinforcement, partial replacement, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting requirements.	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1 GALL V / SRP 3.2 GALL VII / SRP 3.3
XI.M8	BWR Penetrations	The 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 by performing inspection and flaw evaluation in accordance	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		with the guidelines of staff-approved BWRVIP-49-A, BWRVIP-47-A and BWRVIP-27-A and the requirements in the ASME Code, Section XI. The examination categories include volumetric examination methods (ultrasonic testing or radiography testing), surface examination methods (liquid penetrant testing or magnetic particle testing), and visual examination methods.		
XI.M9	BWR Vessel Internals	The program includes inspections and flaw evaluations in conformance with the guidelines of applicable staff-approved BWRVIP documents, and to ensure the long-term integrity and safe operation of BWR vessel internal components that are fabricated of nickel alloy and stainless steel (including martensitic stainless steel, cast stainless steel and associated welds). The program manages the effects of cracking due to 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 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	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		holddown beam bolts by performing visual inspections or stress analyses to ensure 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.		
XI.M10	Boric Acid Corrosion	This program relies, in part, on the response to NRC Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,” to identify, evaluate, and correct borated water leaks that could cause corrosion damage to reactor coolant pressure boundary components. The program also includes inspections, evaluations, and corrective actions for all components subject to aging management review that may be adversely affected by some form of borated water leakage. This program includes provisions to initiate evaluations and assessments when leakage is discovered by activities not associated with the program. This program follows the guidance described in Section 7 of WCAP-15988-NP, Revision 2, “Generic Guidance for an Effective Boric Inspection Program for Pressurized Water Reactors.”	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1 GALL V / SRP 3.2 GALL VI / SRP 3.6 GALL VII / SRP 3.3 GALL VIII / SRP 3.4 GALL III / SRP 3.5

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
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 pressurized water reactor primary coolant at elevated temperature. The scope of this program includes the following groups of components and materials: (a) all nickel alloy components and welds which are identified in EPRI MRP-126; (b) nickel alloy components and welds identified in ASME Code Cases N-770, N-729 and N-722, as incorporated by reference in 10 CFR 50.55a; and (c) components that are susceptible to corrosion by boric acid and may be impacted 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. Unless required at a greater frequency by 10 CFR 50.55a, all susceptible nickel alloy components and welds (e.g., Alloy 600/82/182 branch connection nozzles and welds) are volumetrically inspected at an interval not to exceed 10 years if such components or welds are: (a) in contact with reactor coolant; and (b) relied upon for substantial strength of the components or welds, and are of sufficient size to create a loss of coolant accident (LOCA) through a completed failure (guillotine break) or ejection of the component. Other nickel alloy components and welds within the scope of this program are inspected in	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		accordance with EPRI MRP-126. This program also performs an inspection of bottom-mounted instrumentation (BMI) nozzles of reactor pressure vessels using a qualified volumetric examination method. The inspection is conducted on all BMI nozzles prior to the subsequent period of extended operation to ensure adequate management of cracking due to PWSCC. If this inspection indicates the occurrence of PWSCC, periodic volumetric inspections are performed on these nozzles and adequate inspection periodicity is established. Alternatively, plant-proposed and staff-approved mitigation methods may be used to manage the aging effect for these components.		
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	The program consists of the determination of the susceptibility potential significance of loss of fracture toughness due to thermal aging embrittlement of CASS piping, piping components, and piping elements in both the BWR and PWR reactor coolant pressure boundaries emergency core cooling system (ECCS) systems, including interfacing pipe lines to the chemical and volume control system and to the spent fuel pool; and in BWR ECCS systems, including interfacing pipe lines to the suppression chamber and to the drywell and suppression chamber spray system in regard to thermal aging embrittlement based on the casting method, molybdenum content, and ferrite percentage. For potentially susceptible piping, piping components, and piping elements, aging management is accomplished either through enhanced volumetric examination, enhanced visual examination, or a component-specific flaw tolerance evaluation.	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1 GALL V / SRP 3.2
XI.M17	Flow-Accelerated	The program is based on the response to NRC Generic Letter	SLR program is	GALL IV / SRP

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
	Corrosion (FAC)	89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," and relies on implementation of the Electric Power Research Institute guidelines in the Nuclear Safety Analysis Center 202L [(as applicable) Revision 2, 3, or 4], "Recommendations for an Effective Flow Accelerated Corrosion Program." The program includes the use of predictive analytical software [(as applicable) CHECWORKS™, BRT CICERO™, COMSY]. [(if applicable) This program also manages wall thinning caused by mechanisms other than FAC, in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms.] This program includes (a) identifying all susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analyses of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporating inspection data to refine FAC models.	implemented prior to the subsequent period of extended operation	3.1 GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP 3.4
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, and industry recommendations, as delineated in 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 TR-104213, 1015336 and 1015337.	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1 GALL V / SRP 3.2 GALL VII / SRP 3.3

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		The program generally includes periodic inspection of closure bolting for indications of loss of preload, cracking, and loss of material due to corrosion, rust, etc. The program also includes preventive measures to preclude or minimize loss of preload and cracking. A related aging management program (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 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.		GALL VIII / SRP 3.4
XI.M19	Steam Generators	This program consists of aging management activities for the steam generator tubes, plugs, sleeves, and secondary side components. This program is governed by plant technical specifications, commitments to NEI 97-06, Revision 3, and the associated EPRI guidelines. The program also includes foreign material exclusion as a means to inhibit 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 on steam generator tubes in accordance with the requirements in the technical specifications to detect aging effects, if they should occur. The technical specifications require condition monitoring and operational assessments to be performed to ensure that the tube integrity will be maintained until the	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		next inspection. Condition monitoring and operational assessments are done in accordance with the technical specification requirements and guidance in NEI 97-06, Revision 3. The program also includes inspections of steam generator components in accordance with the guidance in NEI 97-06, Revision 3.		
XI.M20	Open-Cycle Cooling Water System	The program relies, in part, on implementing the response to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," [(if applicable) and includes nonsafety-related portions of the open-cycle cooling water system]. The program includes (a) surveillance and control of biofouling, (b) tests to verify heat transfer of heat exchangers, (c) routine inspection and maintenance to ensure 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 to ensure aging effects are adequately managed.	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1 GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP 3.4
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 (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the effects of corrosion are minimized; (b) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of	Program should be implemented prior to subsequent period of extended operation	GALL IV / SRP 3.1 GALL V / SRP 3.2 GALL VII / SRP 3.3

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		degradation. The program uses ((as applicable) e.g., EPRI 1007820, Closed Cooling Water Chemistry Guideline, and corrosion coupon testing and microbiological testing).		GALL VIII / SRP 3.4
XI.M22	Boraflex Monitoring	The program consists of (a) neutron attenuation testing (“blackness testing”) to determine gap formation, (b) sampling for the presence of silica in the spent fuel pool along with boron loss, and (c) monitoring and analysis of criticality to assure that the required 5% sub-criticality margin is maintained. This program is implemented in response to NRC GL 96-04.	SLR program is implemented prior to the subsequent period of extended operation	GALL VII / SRP 3.3
XI.M23	Inspection of Overhead Heavy Load and Light Load Handling Related to Refueling) Handling Systems	The program evaluates the effectiveness of maintenance monitoring activities for cranes and hoists. The program includes periodic visual inspections to detect degradation of bridge, rail, and trolley structural components and loss of preload on bolted connections. Volumetric or surface examinations confirm the absence of cracking in high strength bolts. This program relies on the guidance in NUREG-0612, ASME B30.2, and other appropriate standards in the ASME B30 series. These cranes must also comply with the maintenance rule requirements provided in 10 CFR 50.65.	SLR program is implemented prior to the subsequent period of extended operation	GALL VII / SRP 3.3
XI.M24	Compressed Air Monitoring	The program consists of monitoring moisture content and corrosion, and performance of the compressed air system, including (a) preventive monitoring of water (moisture), and other contaminants to keep within the specified limits and (b) inspection of components for indications of loss of material due to corrosion. This program is in response to NRC GL 88-14 and INPO’s Significant Operating Experience Report (SOER) 88-01. It also relies on the guidance from the American Society of Mechanical	SLR program is implemented prior to the subsequent period of extended operation	GALL VII / SRP 3.3

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		Engineers (ASME) operations and maintenance standards and guides (ASME OM-S/G-2012, Division 2, Part 28) and American National Standards Institute (ANSI)/ISA-~~S~~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 for signs of loss of material due to corrosion.		
XI.M25	BWR Reactor Water Cleanup System	This program includes ISI and monitoring and control of reactor coolant water chemistry. Related to the inspection guidelines for the reactor water cleanup system (RWCU) inspections of RWCU piping welds that are located outboard of the second containment isolation valve, the program includes measures delineated in per the guidelines of NUREG-0313, Revision 2, and NRC GL 88-01, GL 88-01 Supplement 1, and any applicable NRC-approved alternatives to these guidelines and ISI in conformance with the ASME Section XI.	SLR program is implemented prior to the subsequent period of extended operation	GALL VII, SRP 3.3
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 to ensure that their operability is maintained. The program also includes periodic inspection and testing of halon/carbon dioxide fire suppression systems.	SLR program is implemented prior to the subsequent period of extended operation	GALL VII / SRP 3.3
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, fouling, and flow blockage because of fouling by conducting periodic visual inspections, tests, and	Program is implemented 5 years before the subsequent period of extended operation. Inspections	GALL VII / SRP 3.3

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		flushes performed in accordance with the 2011 Edition of 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: (a) normally dry but periodically subjected to flow and (b) cannot be drained or allow water to collect are subjected to augmented testing beyond that specified in NFPA 25, including: (a) periodic system full flow tests at the design pressure and flow rate or internal visual inspections and (b) 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. Non-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.	of wetted normally dry piping segments that cannot be drained or that allow water to collect begin 5 years before the subsequent period of extended operation. The program's remaining inspections begin during the subsequent period of extended operation	
XI.M29	Aboveground Metallic Tanks	This program is a condition monitoring program that manages aging effects associated with outdoor tanks sited on soil or concrete and indoor large-volume tanks containing water designed with internal pressures approximating atmospheric pressure that are sited on concrete or soil, including the [applicant to list the specific tanks that are in the program scope]. The program includes	Program is implemented and inspections begin 10 years before the subsequent period of extended operation.	GALL V / SRP 3.2 GALL VII / SRP 3.3

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		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. 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. Thickness measurements of tank bottoms are conducted to ensure that significant degradation is not occurring. 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.		GALL VIII / SRP 3.4
XI.M30	Fuel Oil Chemistry	This program relies on a combination of surveillance and maintenance procedures. Monitoring and controlling fuel oil contamination in accordance with the guidelines of American Society for Testing and Materials (ASTM) Standards D1796, D2276, D2709, and D4057 maintains the fuel oil quality. 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.	SLR program is implemented prior to the subsequent period of extended operation	GALL VII / SRP 3.3

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
XI.M31	Reactor Vessel Material Surveillance	This program requires implementation of a reactor vessel material surveillance program to monitor the changes in fracture toughness to 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 >1MeV). The surveillance capsules must be located near the inside vessel wall in the beltline region so that the material specimens duplicate, to the greatest degree possible, the neutron spectrum, temperature history, and maximum neutron fluence experienced at the reactor vessel's inner surface. Because of the resulting lead factors, surveillance capsules receive equivalent neutron fluence exposures earlier than the inner surface of the reactor vessel. This allows surveillance capsules to be withdrawn prior to the inner surface receiving an equivalent neutron fluence and therefore test results may bound the corresponding operating period in the capsule withdrawal schedule. This surveillance program must comply with ASTM International (formerly American Society for Testing and Materials) Standard Practice E 185-82, as incorporated by reference in 10 CFR Part 50, Appendix H. Because the withdrawal schedule in Table 1 of ASTM E 185-82 is based on plant operation during the original 40-year initial license term, standby capsules may need to be incorporated into the Appendix H program to ensure appropriate monitoring during the subsequent period of extended operation. Surveillance capsules are designed and located to	The surveillance capsule withdrawal schedule revised before the subsequent period of extended operation	Reactor Vessel Surveillance

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		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. As an alternative to a plant-specific surveillance program complying with ASTM E 185-82, an integrated surveillance program (ISP) may be considered for a set of reactors that have similar design and operating features, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.C. The plant-specific implementation of the ISP is consistent with the latest version of the ISP plan that has received approval by the NRC for the subsequent period of extended operation. The objective of this Reactor Vessel Material Surveillance program is to provide sufficient material data and dosimetry to (a) monitor irradiation embrittlement to neutron fluences greater than the projected neutron fluence at the end of the subsequent period of operation, and (b) provide adequate dosimetry monitoring during the operational period. If surveillance capsules are		

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		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 foot-pound (ft-lb) transition temperature and the drop in the upper-shelf energy as a function of neutron fluence and irradiation temperature. The data from this surveillance program are used to monitor neutron irradiation embrittlement of the reactor vessel, and are inputs to the neutron embrittlement time-limited aging analyses (TLAAs) described in Section 4.2 of the Standard Review Plan for Subsequent License Renewal (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, 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 to the capsule withdrawal schedule, including the conversion of standby capsules into the Appendix H program and extension of the surveillance program for the subsequent period of extended operation, must be approved by the Nuclear Regulatory Commission (NRC) prior to 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)		

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		are maintained for possible future insertion.		
XI.M32	One-Time Inspection	The program is a condition monitoring program consisting of a one-time inspection of selected components to verify: (a) 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; (b) the insignificance of an aging effect; and (c) that long-term loss of materials will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action, and where periodic wall thickness measurements on a representative sample of each environment are not conducted every 5 years up to at least 10 years prior to the subsequent period of extended operation. This program provides inspections that verify that unacceptable degradation is not occurring. It also may trigger additional actions that ensure the intended functions of affected components are maintained during the subsequent period of extended operation. The elements of the program include (a) 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, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to	Inspections should be conducted prior to the subsequent period of extended operation	GALL IV / SRP 3.1 GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP 3.4

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		occur, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) 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. This program is not 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 periods. Periodic inspections are conducted in these cases. 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.		
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	SLR program should be implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1 GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP 3.4

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		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.		
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 diameter less than 4 inches (NPS<4) and greater than or equal to NPS 1. This program provides a one-time volumetric inspection of a sample of this Class 1 piping. This program includes pipes, fittings, branch connections, and all full and partial penetration (socket) welds. The program includes measures to verify that degradation is not occurring, thereby either confirming that there is no need to manage aging-related degradation or validating the effectiveness of any existing program for the subsequent period of extended operation. The one-time inspection program for ASME Code Class 1 small-bore piping includes	SLR program should be implemented prior to subsequent period of extended operation	GALL IV / SRP 3.1

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		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 operating experience indicates design changes have not been implemented to effectively mitigate cracking, periodic inspection is proposed, as managed by a plant-specific AMP. Should evidence of cracking be revealed by a one-time inspection, a periodic inspection is also proposed, as managed by a plant-specific AMP.		
XI.M36	External Surfaces Monitoring of Mechanical Components	This program is a condition monitoring program that manages loss of material, cracking, changes in material properties (of cementitious components), hardening and 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. 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	Program is implemented 6 months before the subsequent period of extended operation and inspections begin during the subsequent period of extended operation.	GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP 3.4

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		subsequent period of extended operation. 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 ensure a singular decision is derived based on observed conditions.		
XI.M37	Flux Thimble Tube Inspection	The 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 US 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."	SLR program is implemented prior to the subsequent period of extended operation	GALL IV / SRP 3.1
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	This program is a condition monitoring program that manages loss of material, cracking, and hardening and loss of strength of polymeric materials. This program consists of visual inspections of all accessible internal surfaces of metallic piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components that are exposed to environments of uncontrolled indoor air, outdoor air, air with borated water	Program is implemented 6 months before the subsequent period of extended operation and inspections begin during the subsequent period of extended	GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		leakage, condensation, moist air, diesel exhaust, and any water environment other than open-cycle cooling water, closed-cycle cooling water, and fire water. Elastomers exposed to open-cycle, closed-cycle cooling water, and fire water are 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. At a minimum, in each 10-year period during the period of extended operation a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each period despite meeting the sampling limit. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this program. If visual inspection of internal surfaces is not possible, a plant-specific program is used. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria are clear enough to reasonably ensure a	operation.	3.4 GALL VI / SRP 3.6

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		singular decision is derived based on observed conditions.		
XI.M39	Lubricating Oil Analysis	This program ensures that the oil environment in the mechanical systems is maintained to the required quality. This program ensures that 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.	SLR program is implemented prior to the subsequent period of extended operation	GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP 3.4
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 percent sub-criticality 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.	SLR program should be implemented prior to the subsequent period of extended operation	GALL VII / SRP 3.3
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, cracking and changes in material properties (for cementitious piping). 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	SLR program should be implemented before the subsequent period of extended operation	GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP 3.4

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		cathodic protection) The number of inspections is based on the effectiveness of the preventive and mitigative actions. Annual cathodic protection surveys are conducted. Where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, actual loss of material rates are measured from in-situ coupons. Inspections are conducted by qualified individuals. Adverse inspection results result in additional inspections. If a reduction in 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, soil testing is conducted once in each 10-year period starting 10 years prior to the subsequent period of extended operation.		
XI.M42	Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks	This program is a condition monitoring program that manages degradation of coatings/linings that can lead to loss of material of base materials and downstream effects such as reduction in flow, reduction in pressure or reduction in heat transfer when coatings/linings become debris. This program manages these aging effects by conducting periodic visual inspections of all coatings/linings applied to the internal surfaces of in-scope components exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, lubricating oil or fuel oil where loss of coating or lining integrity could impact the component's or downstream component's current licensing basis intended function(s). 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	Program is implemented no later than six months before the subsequent period of extended operation and inspections begin no later than the last refueling outage before the subsequent period of extended	GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP 3.4

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		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 is not acceptable. Blisters are evaluated by a coatings specialist with the blisters being surrounded by sound material and with the size and frequency not increasing. Minor cracks in cementitious coatings are acceptable provided 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.	operation.	
XI.S1	ASME Section XI, Subsection IWE Inservice Inspection (IWE)	This program is in accordance with ASME Section XI, Subsection IWE, consistent with 10 CFR 50.55a "Codes and standards," with supplemental recommendations. The AMP includes periodic visual, surface, volumetric examinations, and leak rate testing, where applicable, of metallic pressure-retaining components of steel containments and concrete containments for signs of degradation, damage, irregularities including liner plate bulges, and for coated areas distress of the underlying metal shell or liner, and corrective actions. 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. This program also includes aging management for the potential loss of material due to corrosion in the	SLR program is implemented prior to the subsequent period of extended operation	GALL II / SRP 3.5

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		inaccessible areas of the BWR Mark I steel containment, and surface examination for the detection of cracking of structural bolting. In addition, the program includes supplemental surface or enhanced examinations to detect cracking for specific components [identify components], and supplemental volumetric examinations by sampling 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.		
XI.S2	ASME Section XI, Subsection IWL Inservice Inspection (IWL)	This program consists of (a) periodic visual inspection of concrete surfaces for reinforced and pre-stressed concrete containments, (b) periodic visual inspection and sample tendon testing of un-bonded 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 concrete surfaces based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R.	SLR program is implemented prior to the subsequent period of extended operation	GALL II / SRP 3.5
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 ASME Section XI, Subsection IWF program. This includes inspections of an additional 5 percent of supports outside of the existing IWF sample population. For high-strength bolting in sizes greater than 1 inch nominal diameter, volumetric examination	SLR program is implemented prior to the subsequent period of extended operation	GALL II / SRP 3.5 GALL III / SRP 3.5

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 should be performed to detect cracking in addition to the VT-3 examination. If a component support does not exceed the acceptance standards of IWF-3400 but is electively repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.		
XI.S4	10 CFR Part 50, Appendix J	This program consists of monitoring leakage rates through the containment system, its shell or liner, associated welds, penetrations, isolation valves, fittings, and other access openings to detect degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. This program is implemented in accordance with 10 CFR Part 50 Appendix J, RG 1.163 and/or NEI 94-01.	SLR program is implemented prior to the subsequent period of extended operation	GALL II / SRP 3.5
XI.S5	Masonry Walls	This program consists of inspections, based on IE Bulletin 80-11 and plant-specific monitoring proposed by 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.	SLR program is implemented prior to the subsequent period of extended operation	GALL III / SRP 3.5
XI.S6	Structures Monitoring	This program consists of periodic visual inspection and monitoring the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as those described in ACI 349.3R, ACI 201.1R, SEI/ASCE 11, and other documents) will be detected, the extent of degradation determined, evaluated, and corrective actions	SLR program is implemented prior to the subsequent period of extended operation	GALL VII / SRP 3.3 GALL II / SRP 3.5 GALL III / SRP

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		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, and of protective coatings for substrate materials. Quantitative results (measurements) and qualitative data from periodic inspections are trended with photographs and surveys for the type, severity, extent, and progression of degradation. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and quantitative acceptance criteria of ACI 349.3R.		3.5 GALL VI / SRP 3.6
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	This program consists of inspection and surveillance of raw-water control structures associated with emergency cooling systems or flood protection. The program also includes structural steel and structural bolting associated with water-control structures. In general, parameters monitored should be in accordance with Section C.2 of R.G. 1.127 and quantitative measurements should be recorded for all applicable parameters monitored or inspected. Inspections should occur at least once every 5 years. Structures exposed to aggressive water require additional plant-specific investigation.	SLR program is implemented prior to the subsequent period of extended operation	GALL III / SRP 3.5
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,	SLR program is implemented prior to the subsequent period of extended operation	GALL III / SRP 3.5

Table XI-01. FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management of Applicable Systems for SLR

AMP	GALL-SLR Program	Description of Program	Implementation Schedule*	Applicable GALL-SLR Report and SRP-SLR Chapter References
		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 ECCS.		
SRP-SLR Appendix A	Plant-Specific AMP	The [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 AERM] by conducting [periodic, one-time] [describe inspection methods and tests] of [all components or a representative sample of components] within the scope of the program. [When applicable, periodic inspections are conducted every XX years commencing prior to or during the subsequent period of extended operation.] [Describe how inspection and test implementing procedures are controlled (e.g., non-ASME Code inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes that ensure an adequate examination).] Qualitative acceptance criteria are clear enough to reasonably ensure a singular decision is derived based on observed conditions. When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the subsequent period of extended operation, additional inspections are performed.	Program should be implemented prior to subsequent period of extended operation	GALL IV / SRP 3.1 GALL V / SRP 3.2 GALL VII / SRP 3.3 GALL VIII / SRP 3.4 GALL II-III / SRP 3.5 GALL VI / SRP 3.6

*An applicant need not incorporate the implementation schedule into its FSAR. However, the reviewer should verify that the applicant has identified and committed in the license renewal application to any future aging management activities to be completed before the subsequent period of extended operation. The staff expects to impose a license condition on any renewed license to ensure that the applicant will complete these activities no later than the committed date.

APPENDIX A

QUALITY ASSURANCE FOR AGING MANAGEMENT PROGRAMS

QUALITY ASSURANCE FOR AGING MANAGEMENT PROGRAMS

The subsequent licensing renewal (SLR) applicant must demonstrate that the effects of aging on structure and component (SC) 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, those 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 10 CFR Part 50. For nonsafety-related SCs subject to an AMR, the existing 10 CFR Part 50, Appendix B, QA program may be used to address the elements of corrective actions, confirmation process, and administrative controls on the following bases:

- 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 GALL-SLR Report AMP XI.M2, “Water Chemistry,” may be used to minimize the piping’s susceptibility to corrosion. However, it also may be necessary to institute a condition monitoring program that uses ultrasonic inspection to verify that corrosion is indeed insignificant.

- As required by 10 CFR 50.34(b)(6)(i), the final safety analysis report (FSAR) submitted by a nuclear power plant license applicant includes information on the applicant’s organizational structure, allocations of responsibilities and authorities, and personnel qualification requirements. 10 CFR 50.34(b)(6)(ii) also notes that Appendix B of 10 CFR Part 50 sets forth the requirements for managerial and administrative controls used for safe operation. Pursuant to 10 CFR 50.36(c)(5), administrative controls related to organization and management, procedures, record keeping, review and audit, and reporting ensure the safe operation of the facility. Programs that are consistent with the requirements of 10 CFR Part 50, Appendix B, also satisfy the administrative controls element necessary for AMPs for SLR.

Notwithstanding the suitability of its provisions to address quality-related aspects of the AMR process for SLR, 10 CFR Part 50, Appendix B, covers only safety-related SCs. Therefore, absent a commitment by the applicant to expand the scope of its 10 CFR Part 50, Appendix B, QA program to include nonsafety-related SCs subject to an AMR for SLR, the AMPs applicable to nonsafety-related SCs include alternative means to address corrective actions, confirmation processes, and administrative controls. Such alternate means are subject to review by the NRC on a case-by-case basis.

An example summary program description of the QA program for the FSAR supplement is shown below.

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule	Applicable GALL-SLR Report and SRP-SLR Chapter References
GALL-SLR Appendix A	Quality Assurance	The QA program, developed in accordance with the requirements of 10 CFR Part 50, Appendix B, provides the basis for the corrective actions, confirmation process, and administrative controls elements of AMPs. The scope of this existing QA program is expanded to also include nonsafety-related SCs subject to AMPs.	Existing program	GALL-SLR IV / SRP-SLR 3.1 GALL-SLR V / SRP-SLR 3.2 GALL-SLR VII / SRP-SLR 3.3 GALL-SLR VIII / SRP-SLR 3.4 GALL SLR II-III/ SRP-SLR 3.5 GALL-SLR VI / SRP-SLR 3.6

APPENDIX B

OPERATING EXPERIENCE FOR AGING MANAGEMENT PROGRAMS

OPERATING EXPERIENCE FOR AGING MANAGEMENT PROGRAMS

Operating experience is a crucial element of an effective aging management program (AMP). It provides the basis to support all other elements of the AMP and, as a continuous feedback mechanism, drives changes to these elements to ensure the overall effectiveness of the AMP. Operating experience 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)), licensing renewal applicants are required to implement programs for the ongoing review of operating experience, such as those established in accordance with Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff," of NUREG–0737, "Clarification of TMI Action Plan Requirements."

The systematic review of plant-specific and industry operating experience concerning aging management and age-related degradation ensures that the 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 operating experience that the effects of aging may not be adequately managed. AMPs should be informed by the review of operating experience on an ongoing basis, regardless of the AMP's implementation schedule.

<u>Acceptable Use of Existing Programs</u>

Programs and procedures relied upon to meet the requirements of 10 CFR Part 50, Appendix B, and provisions in NUREG–0737, Item I.C.5, may be used for the capture, processing, and evaluation of operating experience 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') operating experience program (formerly the Significant Event Evaluation and Information Network (SEE-IN) program endorsed in 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 operating experience 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 operating experience, they are also subject to further review as discussed below.

<u>Areas of Further Review</u>

To ensure that the programmatic activities for the ongoing review of operating experience are adequate for SLR, the following points should be addressed:

- The programs and procedures relied upon to meet the requirements of 10 CFR Part 50, Appendix B, and provisions in NUREG–0737, Item I.C.5, explicitly apply to and otherwise would not preclude the consideration of operating experience on age-related degradation and aging management. Such operating experience can constitute information on 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, Appendix B, program to include nonsafety-related SCs.

- All final license renewal interim staff guidance documents and revisions to the GALL-SLR Report should be considered as sources of industry operating experience and evaluated accordingly. There should be a process to identify such documents and process them as operating experience.

- All incoming plant-specific and industry operating experience should be screened to determine whether it may involve age-related degradation or impacts to aging management activities.

- A means should be established within the corrective action program to identify, track, and trend operating experience that specifically involves age-related degradation. There should also be a process to identify adverse trends and to enter them into the corrective action program for evaluation.

- Operating experience items identified as potentially involving aging should receive further evaluation. This evaluation should specifically take into account the following: (a) systems, structures, and components, (b) materials, (c) environments, (d) aging effects, (e) aging mechanisms, (f) AMPs, and (g) the activities, criteria, and evaluations integral to the elements of the AMPs. The assessment of this information should be recorded with the operating experience evaluation. If it is found through evaluation that any effects of aging may not be adequately managed, then a corrective action should be entered into the 10 CFR Part 50, Appendix B, program to either enhance the AMPs or develop and implement new AMPs.

- Assessments should be conducted on the effectiveness of the aging management programs and activities. These assessments should be conducted on a periodic basis that is not to exceed once every five 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 aging management program or activity against the latest NRC and industry guidance documents and standards that are relevant to the particular program or activity. If there is an indication that the effects of aging are not being adequately managed, then a corrective action is entered into the 10 CFR Part 50, Appendix B, program to either enhance the AMPs or develop and implement new AMPs, as appropriate.

- Training on age-related degradation and aging management should be provided to those personnel responsible for implementing the AMPs and those personnel who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry operating experience. The scope of training should be linked to the responsibilities for processing operating experience. 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 operating experience on age-related degradation and aging management to the industry. This reporting should be accomplished through participation in the INPOs’ operating experience 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 concerning age-related degradation and aging management should be described in the subsequent license renewal application (SLRA), including the Final Safety Analysis Report (FSAR) supplement. Alternate approaches for the future consideration of operating experience are subject to NRC review on a case-by-case basis. An example summary program description of the operating experience program for the FSAR supplement is shown below.

GALL-SLR AMP	GALL-SLR Program	Description of Program	Implementation Schedule	Applicable GALL-SLR Report and SRP-SLR Chapter References
GALL-SLR Appendix B	Operating Experience	This program captures the operating experience from plant-specific and industry sources and is systematically reviewed on an ongoing basis in accordance with the QA program, which meets the requirements of 10 CFR Part 50, Appendix B, and the operating experience 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 INPO operating experience program, as endorsed by the NRC. In accordance with these programs, all incoming operating experience items are screened to determine whether they may involve age-related degradation or aging management impacts. Items so identified are further evaluated and the AMPs are either enhanced or new AMPs are developed, as appropriate, when it is determined through these evaluations that the effects of aging may not be adequately managed. Training on age-related degradation and aging management is provided to those personnel responsible for implementing the AMPs and who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry operating experience. Plant-specific operating experience associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the operating experience program.	Existing Program	GALL-SLR IV / SRP-SLR 3.1 GALL-SLR V / SRP-SLR 3.2 GALL-SLR VII / SRP-SLR 3.3 GALL-SLR VIII / SRP-SLR 3.4 GALL SLR II-III/ SRP-SLR 3.5 GALL-SLR VI / SRP-SLR 3.6

NRC FORM 335
(12-2010)
NRCMD 3 7

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

(See instructions on the reverse)

1 REPORT NUMBER
(Assigned by NRC, Add Vol., Supp , Rev., and Addendum Numbers, If any)

NUREG-2191, Vol. 2
Draft

2 TITLE AND SUBTITLE

Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report, Volume 2
Draft Report for Comment

3. DATE REPORT PUBLISHED

MONTH	YEAR
December	2015

4 FIN OR GRANT NUMBER

5 AUTHOR(S)

U.S. Nuclear Regulatory Commission

6 TYPE OF REPORT

Technical

7 PERIOD COVERED (Inclusive Dates)

8. PERFORMING ORGANIZATION - NAME AND ADDRESS (If NRC, provide Division, Office or Region, U S Nuclear Regulatory Commission, and mailing address, if contractor, provide name and mailing address)

Division of License Renewal
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulator Commission

9 SPONSORING ORGANIZATION - NAME AND ADDRESS (If NRC, type "Same as above", if contractor, provide NRC Division, Office or Region, U S Nuclear Regulatory Commission, and mailing address)

Same as item 8, above

10 SUPPLEMENTARY NOTES

11 ABSTRACT (200 words or less)

The Generic Aging lessons Learned for Subsequent License Renewal (GALL-SLR) Report contains the staff's generic evaluation of the aging management programs for subsequent license renewal (i.e., for operation from 60 to 80 years). The guidance documents for first license renewal (i.e., for operation from 40 to 60 years) have been reviewed to determine where the programs for first license renewal should be augmented for subsequent license renewal. The report recognizes that there will be new issues due to long-term exposure to radiation and high temperature that will present new challenges to nuclear power plant managers in maintaining safety and reliability. This document identifies the structures and components in the scope of license renewal and provides generic programs for addressing these aging issues. Where it was not possible to develop a generic program, this document suggests that aging issues be addressed by a further evaluation or a plant-specific aging management program. The aging management programs in this document are intended for utilities wishing to submit subsequent license renewal applications. However, the programs described in this document may be used for applications for first license renewal.

12 KEY WORDS/DESCRIPTORS (List words or phrases that will assist researchers in locating the report.)

License Renewal
Long-term Operations
Aging
Nuclear Safety
Aging Mechanisms
Aging Effects
Aging Management Programs
Subsequent License Renewal
Second License Renewal
Further Evaluations

13 AVAILABILITY STATEMENT
unlimited

14 SECURITY CLASSIFICATION
(This Page)
unclassified
(This Report)
unclassified

15 NUMBER OF PAGES

16 PRICE

NUREG-2191, Vol. 2
Draft

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

December 2015