Virgil C. Summer Nuclear Station

Application for Subsequent License Renewal

August 2023

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Virgil C. Summer Nuclear Station

Application for Subsequent License Renewal

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1.0 ADMINISTRATIVE INFORMATION

1.1 GENERAL INFORMATION

1.1.1 NAME OF APPLICANTS

- Dominion Energy South Carolina, Inc. (Dominion, Dominion Energy South Carolina, or DESC), two-thirds ownership
- South Carolina Public Service Authority (Santee Cooper), one-third ownership

1.1.2 ADDRESS OF APPLICANTS

Dominion Energy South Carolina, Inc.	South Carolina Public Service Authority
400 Otarre Parkway	P. O. Box 2946101
Cayce, SC 29033	Moncks Corner, SC 29461-2901

1.1.3 DESCRIPTION OF BUSINESS OR OCCUPATION OF APPLICANT

Dominion Energy South Carolina, Inc., a public utility headquartered in Cayce, South Carolina, is a South Carolina corporation organized in 1924. Dominion Energy South Carolina, Inc. is a wholly-owned subsidiary of SCANA, which is a wholly-owned subsidiary of Dominion Energy. Dominion Energy South Carolina, Inc. conducts business under the name “Dominion Energy South Carolina.”

Dominion Energy South Carolina is engaged in the generation, transmission and distribution of electricity to approximately 782,000 customers in the central, southern and southwestern portions of South Carolina. Additionally, Dominion Energy South Carolina distributes natural gas to approximately 435,000 residential, commercial and industrial customers in South Carolina. Outstanding shares of common and preferred stock are held by SCANA, a wholly-owned subsidiary of Dominion Energy, Inc.

Santee Cooper is a state-owned electric and water utility that serves more than 204,000 residential and commercial customers in Berkeley, Georgetown, and Horry counties. The utility supplies power to the municipalities of Bamberg and Georgetown, 30 large industrial customers, and Charleston Air Force Base. Santee Cooper generates the power distributed by some of South Carolina's electric cooperatives.

Dominion Energy South Carolina, Inc. is authorized to act as agent for the South Carolina Public Service Authority. Dominion Energy South Carolina is the current licensed owner and operator of Virgil C. Summer Nuclear Station, Unit 1, which is the subject of this subsequent license renewal application (SLRA).

The current first renewed operating license will expire midnight on August 6, 2042 (Facility Operating License No. NPF-12).

Dominion Energy South Carolina will continue as the licensed owner and operator for the subsequent renewed operating license.

1.1.4 DESCRIPTION OF ORGANIZATION AND MANAGEMENT OF APPLICANT

Dominion Energy South Carolina is submitting this application on its own behalf and on behalf of Santee Cooper. Otherwise, neither DESC nor Santee Cooper is acting as agent or representative of any other person in filing this application.

Dominion Energy South Carolina is not owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government. The names and business addresses of the DESC directors and principal officers as of August 1, 2023 are provided below. All directors and principal officers are citizens of the United States:

Name	Business Address
Robert M. Blue Director	120 Tredegar Street; PH-3 Richmond, VA 23219
W. Keller Kissam Director - President	400 Otarre Parkway; Building D; 3rd Floor Cayce, SC 29172
Diane Leopold Director - Chief Executive Officer	120 Tredegar Street; PH-3 Richmond, VA 23219
Carter M. Reid Executive Vice President, Chief of Staff and Corporate Secretary	120 Tredegar Street; PH-3 Richmond, VA 23219
Corynne S. Arnett Senior Vice President - Regulatory Affairs and Customer Experience	120 Tredegar Street; PH-3 Richmond, VA 23219
Carlos M. Brown Senior Vice President, Chief Legal Officer and General Counsel	120 Tredegar Street; PH-3 Richmond, VA 23219
Michele L. Cardiff Senior Vice President, Controller and Chief Accounting Officer	120 Tredegar Street; RS-2 Richmond, VA 23219

Name	Business Address
William L. Murray Senior Vice President - Corporate Affairs & Communications	120 Tredegar Street; PH-3 Richmond, VA 23219
Stephen D. Ridge Senior Vice President and Chief Financial Officer	120 Tredegar Street; PH-3 Richmond, VA 23219
Eric S. Carr President - Nuclear Operations and Chief Nuclear Officer	5000 Dominion Blvd. Glen Allen, VA 23060
W. Keith Windle Senior Vice President – Administrative Services	120 Tredegar Street; PH-2 Richmond, VA 23219
Utibe O. Bassey Vice President – Customer Experience	600 Canal Street 14th Floor Richmond, VA 23219
Elizabeth “Betsy” L. Chester Vice President – Regulatory Affairs	120 Tredegar Street; RS-3 Richmond, VA 23219
L. Wayne Duman Vice President - Financial Planning & Analysis	120 Tredegar Street; PH-3 Richmond, VA 23219
Iris N. Griffin Vice President – Power Generation	400 Otarre Parkway; Building B Cayce, SC 29172
D. Russell “Rusty” Harris Vice President and General Manager – North Carolina & South Carolina Gas Distribution	800 Gaston Road Dominion Energy Building A Gastonia, NC 28056
James Holloway Vice President - Nuclear Engineering & Fleet Support	5000 Dominion Blvd. Glen Allen, VA 23060
Darius A. Johnson Vice President and Treasurer	120 Tredegar Street, PH-2 Richmond, VA 23219
Douglas C. Lawrence Senior Vice President - Nuclear Operations & Fleet Performance	5000 Dominion Blvd. Glen Allen, VA 23060

Name	Business Address
M. Brandon Phibbs Vice President – Financial Management	400 Otarre Parkway Building B Cayce, SC 29172
Prabir Purohit Vice President - Strategy	120 Tredegar Street, PH-2 Richmond, VA 23219
M. Shaun Randall Vice President – Transmission & Delivery	400 Otarre Parkway Building B Cayce, SC 29172
Alma W. Showalter Vice President - Tax	120 Tredegar Street, PH-2 Richmond, VA 23219
Amanda “Mandy” B. Tornabene Vice President - Governance and Assistant Corporate Secretary	120 Tredegar Street, 4th Floor Richmond, VA 23219
Wendy T. Wellener Vice President - Shared Services	120 Tredegar Street, PH-2 Richmond, VA 23219
Mary “Molly” A. Parker Vice President – Environmental & Sustainability	120 Tredegar Street, CH-2 Richmond, VA 23219
Robert L. Justice Site Vice President – V.C. Summer Power Station	P. O. Box 88 Jenkinsville, SC 29065

Santee Cooper is not owned, controlled or dominated by an alien, a foreign corporation, or a foreign government. All officers and directors of Santee Cooper are citizens of the United States of America. Santee Cooper is governed by a 14-member board of directors. Twelve members are appointed by the Governor, deemed fully qualified by the Senate Public Utilities Review Committee and confirmed by the state Senate. These include one from each of the state's congressional districts; one from each of the three counties (Berkeley, Georgetown and Horry) where Santee Cooper serves retail customers directly; two Directors with previous electric cooperative experience; and a Chairman appointed at large. Two members are Ex Officio and represent Central Electric Power Cooperative, Santee Cooper’s largest customer: one is the Central Chair or designee and the other is elected by the Central Board of Trustees.

Provided below are the names of Santee Cooper's directors and officers, as of July 10, 2023, whose business address is located at P. O. Box 2946101, 1 Riverwood Drive, Moncks Corner, SC 29461-2901:

Name
Peter M. McCoy, Jr. Chairman (At-Large)
Stephen H. Mudge 1st Vice Chairman (At-Large)
David F. Singleton 2nd Vice Chairman (Horry County)
Kristopher D. Clark Director (3rd Congressional District)
Charles S. Bennett II Director (1st Congressional District)
Merrell W. Floyd Director (7th Congressional District)
J. Calhoun Land, IV Director (6th Congressional District)
Charles H. Leaird Director (5th Congressional District)
John S. West Director (Berkeley County)
Dan J. Ray Director (Georgetown County)
Stacy K. Taylor Director (2nd Congressional District)
Charles E. Dalton Director (4th Congressional District)
Robert G. Ardis, III Director (Ex Officio)

Name
E. Paul Basha Director (Ex Officio)
Jimmy D. Staton President & CEO
Michael J. Finissi Chief Operations Officer
Kenneth W. Lott, III Chief Financial & Administration Officer
Pamela J. Williams Chief Public Affairs Officer & General Counsel
Victoria N. Budreau Chief Customer Officer
Monique L. Washington Chief Audit and Risk Officer
Rahul Dembla Chief Planning Officer
J. Martine “Marty” Watson Chief Commercial Officer
Traci J. Grant Director Corporate Services & Corporate Secretary
Dominick G. Maddalone Sr. Director of Innovation and Chief Information Officer
Suzanne H. Ritter Treasurer & Director Financial Planning
Daniel T. Manes Controller

1.1.5 CLASS OF LICENSE, USE OF FACILITY, AND PERIOD OF TIME FOR WHICH THE LICENSE IS SOUGHT

Dominion Energy South Carolina requests renewal of the initial renewed operating license for a period of 20 years beyond the current expiration date shown below to permit the continued generation and distribution of electric energy from Virgil C. Summer Nuclear Station (VCSNS), Unit 1.

Unit	License No.	License Class	Expiration Date
1	NPF-12	104b	August 6, 2042

In this SLRA, Dominion Energy South Carolina also requests renewal of the source, special nuclear material, and by-product license that is included within the initial renewed operating license and that was issued pursuant to 10 CFR Parts 30, 40, and 70.

1.1.6 EARLIEST AND LATEST DATES FOR ALTERATIONS, IF PROPOSED

Dominion proposes to implement modifications associated with the Open Cycle Cooling System program (B2.1.11) and the Buried and Underground Piping and Tanks program (B2.1.28) on a schedule established in Table A4.0-1, "Subsequent License Renewal Commitments." In accordance with 10 CFR 54.21(b), during NRC review of this SLRA, an annual update to the SLRA to reflect any change to the current licensing basis (CLB) that materially affects the content of the SLRA will be provided.

1.1.7 RESTRICTED DATA

With regard to the requirements of 10 CFR 54.17(f), this SLRA does not contain any "Restricted Data," as that term is defined in the Atomic Energy Act of 1954, as amended, or other defense information, and it is expected that NRC review of this request will not involve any such information.

In accordance with the requirements of 10 CFR 54.17(g), Dominion Energy South Carolina will not permit any individual to have access to, or any facility to possess, Restricted Data or classified National Security Information until the individual and/or facility has been approved for such access under the provisions of 10 CFR Parts 25 and/or 95.

1.1.8 REGULATORY AGENCIES

The Federal Energy Regulatory Commission and the Public Service Commission of South Carolina are the principal regulators of Dominion Energy South Carolina's electric operations in South Carolina. The contact names and addresses for these regulatory agencies are as follows:

Kimberly D. Bose, Secretary
Debbie-Anne A. Reese, Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Jocelyn Boyd, Chief Clerk/Executive Director
Public Service Commission of South Carolina
101 Executive Center Drive, Suite 100
Columbia, South Carolina 29210

1.1.9 LOCAL NEWS PUBLICATIONS

Local news publications that circulate in the area around Virgil C. Summer Nuclear Station are as follows:

The State Newspaper
P. O. Box 1333
Columbia, SC 29202

1.1.10 CONFORMING CHANGES TO STANDARD INDEMNITY AGREEMENT

10 CFR 54.19(b) requires that license renewal applications include “conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license.” The current Indemnity Agreement (No. B-86) for Virgil C. Summer Nuclear Station states in Article VII that the Agreement shall terminate at the time of expiration of the license specified in Item 3 of the Attachment (to the Agreement). Item 3 of the Attachment to the Indemnity Agreement, as revised through Amendment No. 3, lists Virgil C. Summer Nuclear Station operating license number as NPF-12. The original Indemnity Agreement and the Amendments have been reviewed. Neither Article VII nor Item 3 of the Attachment specifies an expiration date for license number NPF-12. Therefore, no changes to the Indemnity Agreement are deemed necessary as part of this application. Should the license number be changed by Nuclear Regulatory Commission (NRC) upon issuance of the subsequent renewed license, Dominion Energy South Carolina requests that NRC amend the Indemnity Agreement to include conforming changes to Item 3 of the Attachment and other affected sections of the Agreement.

1.2 GENERAL LICENSE INFORMATION

1.2.1 APPLICATION UPDATES, RENEWED LICENSE, AND RENEWAL TERM OPERATION

In accordance with 10 CFR 54.21(b), during NRC review of this SLRA, an annual update to the application to reflect any change to the current licensing basis that materially affects the content of the SLRA will be provided.

In accordance with 10 CFR 54.21(d), Dominion Energy South Carolina will maintain a summary list in the Final Safety Analysis Report (FSAR) of activities that are required to manage the effects of aging for the systems, structures or components within the scope of license renewal during the subsequent period of extended operation and summaries of the time-limited aging analyses evaluations.

1.2.2 CONTACT INFORMATION

Any notices, questions, or correspondence in connection with this filing should be directed to:

Mr. Eric S. Carr
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Glen Allen, VA 23060-6711
(Eric.S.Carr@dominionenergy.com)

with copies to:

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1.3 PURPOSE

This document provides information required by 10 CFR Part 54 to support the SLRA for renewal of the initial renewed operating license. The SLRA contains technical information required by 10 CFR 54.21 and environmental information required by 10 CFR 54.23. The information contained herein is intended to provide the NRC with an adequate basis to make the findings required by 10 CFR 54.29.

1.4 DESCRIPTION OF THE PLANT

Virgil C. Summer Power Station Unit 1 is located north (2.5 miles) of Parr, South Carolina. Parr is the site of existing fossil and hydro power stations operated by SCE&G[1] and the decommissioned, experimental Carolinas Virginia Tube Reactor. The plant site is adjacent to a man-made reservoir created by placing a series of dams across Frees Creek, a tributary of the Broad River in western Fairfield County, South Carolina. The resulting Monticello Reservoir provides water requirements for the nuclear station and a pumped storage facility. The reservoir is located east of the Broad River and west of South Carolina State Highway 215, about 26 miles north of Columbia, South Carolina. The unit includes a three-coolant-loop, pressurized light water reactor nuclear steam supply system designed and furnished by Westinghouse Electric Corporation, and a turbine generator designed and furnished by General Electric Company. The balance of the plant was designed and constructed by SCE&G[1] with the assistance of its agent, Gilbert Associates, Inc. The reactor unit is operated at a licensed power output of 2900 MWt, with a gross electrical output of approximately 950 MWe.

1. On April 29, 2019, “South Carolina Electric & Gas Company” (SCE&G) changed its name to “Dominion Energy South Carolina, Inc.”

Dominion Energy South Carolina also operates an independent spent fuel storage installation (ISFSI) at the site. The ISFSI operates under a separate license issued pursuant to the provisions of 10 CFR Part 72 (Reference 1.7-1). Therefore, the ISFSI is not addressed in this application.

1.5 APPLICATION STRUCTURE

In accordance with the requirements of 10 CFR Part 54 (Reference 1.7-2), this SLRA provides the technical and environmental information required for renewal of the initial renewed operating license for an additional 20 years.

This SLRA is structured in accordance with Regulatory Guide 1.188, “Standard Format and Content for Applications to Renew Nuclear Plant Operating Licenses,” (Reference 1.7-3) and NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal,” (Reference 1.7-4). In addition, Section 3, “Aging Management Review Results,” and Appendix B, “Aging Management Programs,” are structured to address the guidance provided in NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants,” (Reference 1.7-5). NUREG-2192 references NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,” (Reference 1.7-6). NUREG-2191 was used to determine the adequacy of existing programs for purposes of managing aging and which existing programs should be augmented for subsequent license renewal. The results of the aging management review, using NUREG-2191, have been documented and are illustrated in table format in Section 3, “Aging Management Review Results,” of this application.

This SLRA and supporting environmental report are intended to provide sufficient information for the NRC to complete its technical and environmental reviews and enable the NRC to make the findings required by 10 CFR 54.29 in support of renewal of the initial renewed operating licenses.

The SLRA is organized into four Chapters and five Appendices as follows:

Section 1.0 - Administrative Information

Section 1.0 provides the administrative information required by 10 CFR 54.17 and 10 CFR 54.19. This section describes the plant and states the purpose for this application. Included in this chapter are the names, addresses, business descriptions, organization, and management descriptions of the applicant, as well as other administrative information. Also provided is an overview of the structure of the SLRA and a listing of acronyms and general references used throughout the SLRA.

Section 2.0 - Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation Results

Section 2.0 describes and justifies the methods used in the integrated plant assessment to identify those structures and components subject to an aging management review in accordance with the requirements of 10 CFR 54.21(a)(2). These methods consist of: (1) scoping, which identifies the plant systems, structures, and components (SSCs) that are within the scope of 10 CFR 54.4(a), and (2) screening under 10 CFR 54.21(a)(1), which identifies those in-scope SSCs that perform intended functions without moving parts or a change in configuration or properties, and that are not subject to replacement based on a qualified life or specified time period.

Additionally, the scoping results for systems and structures are described in Section 2.0. The plant level scoping results identify the systems and structures within the scope of subsequent license renewal in Section 2.2. The screening results identify components subject to aging management review in Sections 2.3, 2.4, and 2.5.

The screening results consist of lists of component types that require aging management review (AMR). Descriptions of mechanical systems and structures within the scope of license renewal are provided as background information. The descriptions of systems identify subsequent license renewal (SLR) drawings that document the in-scope mechanical components. The SLR drawings are provided in a separate submittal. For each in-scope system and structure, component types requiring an aging management review are identified, associated component intended functions are identified, and the appropriate reference to the Section 3.0 Table providing the AMR results is provided.

Selected structural and electrical component types, such as component supports and cables, were evaluated as commodities. Under the commodity approach, selected structural and electrical component types were evaluated based upon common environments and materials. For each of these commodities, the component types requiring aging management review are presented in Sections 2.4, and 2.5.

Section 3.0 - Aging Management Review

10 CFR 54.21(a)(3) requires a demonstration that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis throughout the subsequent period of extended operation. Section 3.0 presents the results of the aging management reviews. Section 3.0 is the link between the scoping and screening results provided in Section 2.0 and the aging management programs (AMPs) described in Appendix B.

AMR results are presented in tabular form, in a format in accordance with the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants, NUREG-2192. For mechanical systems, aging management review results are provided in Sections 3.1, 3.2, 3.3, and 3.4 for the reactor vessel, reactor vessel internals, and reactor coolant system; engineered safety features; auxiliary systems; and steam and power conversion systems, respectively. AMR results for Containment, structures, and component supports are provided in Section 3.5. AMR results for electrical and instrumentation and controls are provided in Section 3.6.

Section 4.0 - Time-Limited Aging Analyses

Time-limited aging analyses (TLAAs), as defined by 10 CFR 54.3, are listed in this section. Section 4.0 includes each of the TLAAs identified in NUREG-2192 and in plant-specific analyses. This section includes a summary of the time-dependent aspects of the analyses. A demonstration is provided to show that: (1) each of the analyses remains valid for the subsequent period of extended operation, (2) the analyses have been projected to the end of the subsequent period of extended operation, or (3) the effects of aging on the intended function(s) will be adequately managed for the subsequent period of extended operation.

Section 4.0 also confirms that plant-specific exemptions granted pursuant to 10 CFR 50.12 that are based upon a TLAA, as defined in 10 CFR 54.3, were identified. Therefore, no further evaluation is required for plant-specific exemptions granted pursuant to 10 CFR 50.12.

Appendix A - FSAR Supplement

The Final Safety Analysis Report (FSAR) supplement is found in Appendix A and contains a summary of aging management programs credited for managing the effects of aging for the subsequent period of extended operation. In addition, summary descriptions and dispositions of TLAA evaluations and a summary of subsequent license renewal commitments are provided. The subsequent license renewal commitments are identified in Table A4.0-1, Subsequent License Renewal Commitments. The information in Appendix A fulfills the requirements in 10 CFR 54.21(d).

Appendix B - Aging Management Programs

Appendix B describes the programs that are credited for managing aging effects for components and structures during the subsequent period of extended operation based upon the AMR results provided in Section 3.0 and the TLAA results provided in Section 4.0. The information in Section 2.0, Section 3.0, and Appendix B fulfills the requirements of 10 CFR 54.21(a).

Appendix C - (Optional)

Appendix C is an optional appendix an applicant may use for any plant-specific information which may assist the NRC during their review of the application.This appendix is not used.

Appendix D - Technical Specification Changes

Appendix D satisfies the requirements of 10 CFR 54.22 to include any Technical Specification changes or additions necessary to manage the effects of aging during the subsequent period of extended operation as part of the renewal application. Since no Technical Specification changes are requested, this appendix is not used.

Appendix E - Environmental Information

Appendix E satisfies the requirements of 10 CFR 54.23 to provide a supplement to the Environmental Report that complies with the requirements of subpart A of 10 CFR Part 51 (Reference 1.7-12).

1.6 ACRONYMS

Table 1.6-1 Acronyms

Acronym	Definition
AAC	Alternate Alternating Current
AC	Alternating Current
ACAR	Aluminum Conductor Aluminum Reinforced
ACI	American Concrete Institute
ACSR	Aluminum Conductor Steel Reinforced
ALE	Adverse Localized Environments
AMA	Aging Management Activity
AMP	Aging Management Program
AMR	Aging Management Review
AMSAC	ATWS Mitigation System Actuation Circuit
ANS	American Nuclear Society
ANSI	American National Standards Institute
API	American Petroleum Institute
AR	Aspect Ratio
ART	Adjusted Reference Temperature
ASME	American Society of Mechanical Engineers
ASR	Alkali-Silica Reaction
ASTM	American Society for Testing and Materials

Table 1.6-1 Acronyms

Acronym	Definition
ATWS	Anticipated Transients Without SCRAM
B&PV	Boiler & Pressure Vessel
B&W	Babcock and Wilcox
BMI	Bottom Mounted Instrumentation
BPWORKS™	Buried Pipe Workstation
BTP	Branch Technical Position
BWR	Boiling Water Reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CASS	Cast Austenitic Stainless Steel
CC	Code Case
CE	Combustion Engineering
CEO	Chief Executive Officer
CF	Chemistry Factors
CFR	Code of Federal Regulations
CHAMPS	Component History And Maintenance Planning System
CHECWORKS-SFA™	Chexal-Horowitz Erosion Corrosion Workstation - Steam/Feed Application
CLB	Current Licensing Basis
CR	Condition Report

Table 1.6-1 Acronyms

Acronym	Definition
CRDM	Control Rod Drive Mechanism
CRGT	Control Rod Guide Tube
CSPE	Chlorosulfonated Polyethylene
CUF	Cumulative Usage Factor
CvUSE	Charpy Upper Shelf Energy
DA	Degradation Assessment
DC	Direct Current
DESC	Dominion Energy South Carolina
DM	Dissimilar Metal
DO	Dissolved Oxygen
DOE	Department of Energy
DRPI	Digital Rod Position Indication
EAF	Environmentally-Assisted Fatigue
ECCS	Emergency Core Cooling Systems
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EDS	Equipment Data System
EFPY	Effective Full-Power Years
EPA	Environmental Protection Agency

Table 1.6-1 Acronyms

Acronym	Definition
EPDM	Ethylene Propylene Diene Monomer
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
EQDB	Equipment Qualification Database
ESF	Engineered Safety Features
ET	Eddy Current Test
EVT	Enhanced Visual Test
FAC	Flow Accelerated Corrosion
FAO	Free Available Oxidant
FCG	Fatigue Crack Growth
FERC	Federal Electric Reliability Council
FF	Fluence Factor
FIV	Flow Induced Vibration
FPP	Fire Protection Plan
FSAR	Final Safety Analysis Report
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GDC	General Design Criterion
GL	Generic Letter

Table 1.6-1 Acronyms

Acronym	Definition
GSI	Generic Safety Issue
HELB	High-Energy Line Break
HVAC	Heating, Ventilation, and Air Conditioning
HVT	High-Voltage Termination
IASCC	Irradiation-Assisted Stress Corrosion Cracking
ID	Inner Diameter
IE	Inspection and Enforcement
IEB	Inspection and Enforcement Bulletin
IEN	Inspection and Enforcement Notice
IGSCC	Intergranular Stress Corrosion Cracking
ILRT	Integrated Leak Rate Test
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IPA	Integrated Plant Assessment
IR	Insulation Resistance
IR	Interaction Ratio
ISFSI	Independent Spent Fuel Storage Installation
ISG	Interim Staff Guidance
ISI	Inservice Inspection

Table 1.6-1 Acronyms

Acronym	Definition
LBB	Leak-Before-Break
LCMP	Life Cycle Management Program
LFET	Low Frequency Electromagnetic Examination Techniques
LHSI	Low-Head Safety Injection
LLIS	Low-Level Intake Structure
LLRT	Local Leak Rate Test
LM	Leakage Monitoring
LOCA	Loss-of-Coolant Accident
LPMS	Loose Parts Monitoring System
LR	License Renewal
LRA	License Renewal Application
LTOPS	Low Temperature Overpressure Protection System
MEB	Metal Enclosed Bus
MIC	Microbiologically Influenced Corrosion
MOVATS	Motor-Operated Valve Analysis and Test System
MRP	Material Reliability Program
MT	Magnetic Testing
NACE	National Association of Corrosion Engineers

Table 1.6-1 Acronyms

Acronym	Definition
NDE	Non-destructive Examination
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NPF	Nuclear Power Facility
NPS	Nominal Pipe Size
NRC	U.S. Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSSS	Nuclear Steam Supply System
NSR	Non Safety-Related
NTTF	Japan Near Term Task Force
NUREG	Nuclear Regulatory Commission Regulation
OE	Operating Experience
OOS	Out of Specification
P-T	Pressure-Temperature
P&ID	Piping & Instrumentation Diagram
PAG	Predictive Analysis Group
PAMS	Plant Asset Management System
PDI	Performance Demonstration Initiative
PH	Precipitation-Hardened

Table 1.6-1 Acronyms

Acronym	Definition
PLL	Predicted Lower Limit
PM	Preventive Maintenance
PORV	Power Operated Relief Valve
PSW	Primary Shield Wall
PT	Penetrant Testing
PTS	Pressurized Thermal Shock
PWR	Pressurized Water Reactor
PWROG	Pressurized Water Reactor Owners Group
PWRVI	Pressurized Water Reactor Vessel Internals
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
QC	Quality Control
RAPTOR	RApid Parallel Transport Of Radiation
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RFO	Refueling Outage
RG	Regulatory Guide
RI-ISI	Risk Informed - Inservice Inspection
RIS	Regulatory Information Summary

Table 1.6-1 Acronyms

Acronym	Definition
RO	Restricting Orifice
RS	Recirculation Spray
RSG	Replacement Steam Generator
RT_{NDT}	Reference Nil Ductility Transition Temperature
RT_{PTS}	Reference Temperature for Pressurized Thermal Shock
RV	Reactor Vessel
RVI	Reactor Vessel Internals
RVIN	Reactor Vessel Inlet Nozzle
RVLIS	Reactor Vessel Level Instrumentation System
RVON	Reactor Vessel Outlet Nozzle
RWST	Refueling Water Storage Tank
SBO	Station Blackout
SCC	Stress Corrosion Cracking
SCE&G	South Carolina Electric & Gas
SCRAM	Safety Control Rod Axe Man
SCS	Secondary Core Support
SD	Steam Drains
SER	Safety Evaluation Report
SFP	Spent Fuel Pool

Table 1.6-1 Acronyms

Acronym	Definition
SG	Steam Generator
SGIN	Steam Generator Inlet Nozzle
SGON	Steam Generator Outlet Nozzle
SI-TB	Seal Injection - Thermal Barrier
SLR	Subsequent License Renewal
SLRA	Subsequent License Renewal Application
SRP	Standard Review Plan
SOV	Solenoid Operated Valve
SPS	Surry Power Station
SSW	Secondary Shield Wall
SR	Silicone Rubber
SR	Safety Related
SRP	Standard Review Plan
SS	Stainless Steel
SSCs	Systems, Structures, and Components
TB	Technical Bulletin
TS	Technical Specifications
TLAA	Time-Limited Aging Analyses
TR	Topical Report

Table 1.6-1 Acronyms

Acronym	Definition
UPTI	Underground Piping and Tanks Initiative
USE	Upper Shelf Energy
USI	Unresolved Safety Issue
UT	Ultrasonic / Ultrasonic Testing
UV	Ultra-Violet
VCSNS	Virgil C. Summer Nuclear Station
VECASP	Variable Elevation Cask Pedestal
VHP	Vessel Head Penetration
VT	Visual Examination Technique
WCP	Work Control Process
XLPE	Cross-linked Polyethylene

1.7 GENERAL REFERENCES

1.7-1 10 CFR 72, “Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High-Level Radioactive Waste, and Reactor-Related Greater Than Class C Waste.”

1.7-2 10 CFR 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.”

1.7-3 Regulatory Guide 1.188, “Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses.”

1.7-4 NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal,” December 2017.

1.7-5 NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants.”

1.7-6 NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,” (ADAMS Accession Nos. ML17187A031 and ML17187A204).

1.7-7 10 CFR 50.48, “Fire Protection.”

1.7-8 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants.”

1.7-9 10 CFR 50.62, “Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants.”

1.7-10 10 CFR 50.63, “Loss of All Alternating Current Power.”

1.7-11 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”

1.7-12 10 CFR 51, “Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions.”

1.7-13 NUREG-0933, “Resolution of Generic Safety Issues,” U.S. Nuclear Regulatory Commission, Supplement 34, December 2011.

1.7-14 ANSI/ANS-51.1-1983, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.”

1.7-15 10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events.”

1.7-16 10 CFR 50, “Domestic Licensing of Production and Utilization Facilities.”

1.7-17 V. C. Summer Nuclear Station Unit 1 Technical Specifications, Amendment No. 225.

1.7-18 V. C. Summer Nuclear Station Final Safety Analysis Report (FSAR), Revision 23.

1.7-19 NUREG-1437, “Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, US NRC, Revision 1, 2013.

2.0 SCOPING AND SCREENING METHODOLOGY FOR IDENTIFYING STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW AND IMPLEMENTATION RESULTS

This section describes the process for identifying structures and components subject to aging management review (AMR) in the Virgil C. Summer Nuclear Station (VCSNS) integrated plant assessment (IPA). For the systems, structures, and components (SSCs) within the scope of subsequent license renewal, 10 CFR 54.21(a)(1) requires the subsequent license renewal applicant to identify and list those structures and components subject to AMR. Furthermore, 10 CFR 54.21(a)(2) requires that the methods used to implement the requirements of 10 CFR 54.21(a)(1) be described and justified. Section 2 of this application satisfies these requirements.

The integrated plant assessment process is performed in two steps. Scoping refers to the process of identifying the plant systems and structures that are to be included within the scope of subsequent license renewal in accordance with 10 CFR 54.4. The intended functions that are the bases for including the systems and structures within the scope of subsequent license renewal are also identified during the scoping process. Screening refers to the process of determining which components associated with the in-scope systems and structures are subject to aging management review in accordance with 10 CFR 54.21(a)(1) requirements. A detailed description of the scoping and screening process is provided in Section 2.1.

The scoping and screening methodology is implemented in accordance with NEI 17-01, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal (Reference 1.7-4). The plant level scoping results identify the systems and structures within the scope of subsequent license renewal in Section 2.2. The screening results identify components subject to aging management review in the SLRA sections indicated below.

Section 2.3 for mechanical systems.

Section 2.4 for structures and component supports.

Section 2.5 for electrical and instrumentation and control (I&C) systems.

2.1 SCOPING AND SCREENING METHODOLOGY

2.1.1 INTRODUCTION

This introduction provides an overview of the scoping and screening process used. Subsequent sections provide details on how the process was implemented.

The initial step in the scoping process was to define the entire plant in terms of systems and structures. Each of these identified plant systems and structures were evaluated against the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3), to determine if the system or structure performs or supports a safety-related intended function, if the system or structure failure could prevent the satisfactory accomplishment of a safety-related function, or if the system or structure performs functions that demonstrate compliance with the requirements of one of the five subsequent license renewal regulated events. The intended function(s) that are the bases for including systems and structures within the scope of subsequent license renewal were also identified.

Systems that contain mechanical components such as pumps, piping, valves, etc., are addressed as mechanical systems. A mechanical system was included within the scope of subsequent license renewal if any portion of the system met the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), or (a)(3). Mechanical systems determined to be within the scope of subsequent license renewal were then further evaluated to determine those system components that are required to perform or support the identified system intended function(s). The in-scope boundaries of mechanical systems were identified and are described in Section 2.3. These boundaries are also depicted on the subsequent license renewal boundary drawings. Additional details on scoping evaluations and boundary drawing development are provided in Section 2.1.4.5.

A structure was included within the scope of subsequent license renewal if any portion of the structure met the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), or (a)(3). Structures were then further evaluated to determine those structural components that are required to perform or support the identified structure intended function(s). The portions of each structure within the scope of subsequent license renewal that are required to perform or support the identified structure intended function(s) were identified and are described in Section 2.4. Additional details on scoping evaluations and boundary drawing development are provided in Section 2.1.4.5.

Systems that contain Electrical and Instrumentation and Control (I&C) components, but do not contain mechanical components, are addressed as electrical and I&C systems. Electrical and I&C systems were included within the scope of subsequent license renewal if any portion of the system met the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), or (a)(3). Electrical and I&C components within the in-scope electrical and I&C systems were included within the scope of subsequent license renewal. Likewise, electrical and I&C components within in-scope mechanical systems were included within the scope of subsequent license renewal. Additional details on electrical and I&C system scoping are provided in Section 2.1.4.5.

After completion of the scoping, the screening process was performed to evaluate the structures and components within the scope of subsequent license renewal to identify the long-lived and passive structures and components subject to Aging Management Review (AMR). In addition, the passive intended functions of structures and components subject to AMR were identified. Additional details on the screening process are provided in Section 2.1.5.

Selected components, such as equipment supports, structural items (e.g., fire barriers), and passive electrical components, were scoped and screened as commodities. As such, they were not evaluated with the individual system or structure, but were evaluated collectively as a commodity group. Commodity groups utilized are consistent with NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants” (Reference 1.7-5), Table 2.1-6, and previous license renewal applications accepted by the NRC.

2.1.2 INFORMATION SOURCES USED FOR SCOPING AND SCREENING

A number of different current licensing basis (CLB) and design basis information sources were utilized in the scoping and screening process. The CLB is consistent with the definition provided in 10 CFR 54.3. The CLB includes NRC regulations and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent FSAR update as required by 10 CFR 50.71 and the commitments remaining in effect that were made in docketed licensing correspondence such as responses to NRC bulletins, generic letters, and enforcement actions, as well as commitments documented in NRC safety evaluations or licensee event reports. The significant source documentation is discussed below.

These source documents are available in hard copy or electronic format. Document records such as licensing correspondence and NRC Safety Evaluation Reports are available in a searchable database, such that applicable documents can be identified and located by searching the appropriate topic.

2.1.2.1 Final Safety Analysis Report

The FSAR is updated regularly in accordance with the requirements of 10 CFR 50.71(e). The FSAR provided significant input for system and structure descriptions and functions.

2.1.2.2 Engineering Drawings

Engineering drawings provide system, structure, and component configuration details. These drawings were utilized to determine SSC functional requirements, safety classification, environments, materials of construction, etc., in support of scoping, screening and aging management review evaluations.

2.1.2.3 Controlled Plant Component Database

The controlled equipment database is contained within the Plant Asset Management System (PAMS). Prior to 2022, the component database was called the Component History And Maintenance Planning System (CHAMPS) Database. The CHAMPS database has since been migrated into the PAMS component database, and further references to the plant equipment database in this report will reference PAMS.

PAMS provides a comprehensive listing of plant components with controlled fields for unique equipment tag numbers, system designation, environmental qualification (EQ) designation and safety classification. It also provides uncontrolled component details such as plant location and material information or references.

2.1.2.4 NFPA 805 Fire Protection Design Basis Document

On February 11, 2015, license amendment 199 (ML14287A289) transitioned the fire protection licensing basis to NFPA 805. The NFPA 805 Fire Protection Design Basis Document describes the fire protection configuration for the confinement, detection, and suppression of fires, and demonstrates the capability to achieve and maintain safe shutdown conditions in the event of a fire, in support of the Fire Protection Program functions. Supporting engineering documents provide details of specific components and functions that are credited under NFPA-805.

2.1.2.5 Maintenance Rule System Basis Database

The maintenance rule database documents the results of maintenance rule scoping for systems and structures. The maintenance rule database provided an additional source of information to identify system and structure functions.

2.1.2.6 Environmental Qualification Master List

The Equipment Qualification Database (EQDB) identifies electrical equipment which requires environmental qualification. The database provides specific informative data such as: Tag number, manufacturer, model number, purchase order number, equipment qualification documentation package number, etc. The PAMS equipment database (discussed in Section 2.1.2.3) includes a field that identifies the EQ scoping status.

2.1.2.7 Other CLB References

- V. C. Summer Nuclear Station License Renewal Application (Initial LRA)
- NUREG-1787, Safety Evaluation Report Related to the License Renewal of the Virgil C. Summer Nuclear Station
- NRC Safety Evaluation Reports (SERs) include NRC staff review of VCSNS docketed licensing submittals. Some of these documents may contain licensee commitments.
- Engineering evaluations and calculations can provide additional information about the requirements or characteristics associated with the evaluated systems, structures, or components.
- Licensing Correspondence includes relief requests, Licensee Event Reports, and responses to NRC communications such as NRC bulletins, generic letters, or enforcement actions. Some of these documents may contain licensee commitments.

2.1.2.8 Site Walkdowns

Walkdowns were performed to confirm the configuration and material properties of plant systems, structures, and components where that information was not available from plant documentation.

2.1.3 TECHNICAL BASIS DOCUMENTS

Technical basis documents were prepared in support of the subsequent license renewal project. Engineers experienced in nuclear plant systems, programs, and operations prepared the technical basis documents. Technical basis documents contain technical evaluations and bases for decisions or positions associated with subsequent license renewal requirements as described below. Technical basis documents are prepared, reviewed, and approved in accordance with project procedures, and are based on the CLB source documents described in Section 2.1.2.

The following sections describe the technical basis documents associated with the scoping and screening methodology.

2.1.3.1 Subsequent License Renewal Systems and Structures List

A comprehensive list of systems and structures was identified to be evaluated for subsequent license renewal scoping. While there exists a variety of document sources that identify and list the installed systems and structures, no single source provided the comprehensive list in a format appropriate for 10 CFR 54.4 subsequent license renewal system and structure scoping. Therefore, a technical basis document was prepared to establish a comprehensive list of subsequent license renewal systems and structures, and to document the basis for the list. Starting with the systems and structures list derived from the PAMS equipment database, the list was evaluated against the FSAR, plant design drawings, the maintenance rule database, and other plant CLB documents.

Plant systems and structures were arranged into logical groupings for scoping reviews, and the groupings were defined as subsequent license renewal systems, structures and commodity groups. The technical basis document assures plant structures and components included in the scoping review are associated with a system, structure, or commodity group.

The technical basis document grouped subsequent license renewal systems and structures into the following categories:

- Reactor Vessel, Internals, and Reactor Coolant System
- Engineered Safety Features
- Auxiliary Systems
- Steam and Power Conversion System
- Containments, Structures, and Component Supports
- Electrical and Instrumentation and Controls

This grouping of the subsequent license renewal systems and structures is based on the FSAR and the guidance of NUREG-2191 "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," Final Report (Reference 1.7-6). The complete list of systems, structures, and commodity groups evaluated for subsequent license renewal is provided in Section 2.2 of this application.

2.1.3.2 Identification of Safety-Related Systems and Structures

Safety-related systems and structures are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(1) scoping criterion. Mechanical components that have been classified as safety-related are identified as "SR" in the controlled safety classification data field in PAMS. Electrical components that have been classified as safety-related are identified as "1E" in the controlled safety classification data field in PAMS. Safety-related functions described in the FSAR were evaluated against system functions to confirm the PAMS safety-related classification.

Safety classification procedures were reviewed against the subsequent license renewal safety-related scoping criterion in 10 CFR 54.4(a)(1) to confirm that the safety-related classification is consistent with subsequent license renewal requirements.

Safety classifications are determined in accordance with the August 1970 draft of ANS N18.2, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants." Installed safety related (SR) mechanical equipment are classified as Safety Class 1, 2a, 2b, or 3, in accordance with their importance to nuclear safety. This importance, as established by class assignment, is considered in design, materials, manufacture or fabrication, assembly, erection, construction and operation. Section 3.2.2 of the FSAR defines these Safety Classes. Comparison of the ANS N18.2 Safety Class criteria, as implemented, to the criteria of 10 CFR Part 54.4(a)(1) shows that the Safety Classes encompass the systems and equipment that meet the criteria of 10 CFR Part 54.4(a)(1)(i)-(iii).

Therefore, implementation of the safety-related classification is consistent with 10 CFR 54.4(a)(1) and results in a comprehensive list of safety-related systems and structures that were included within the scope of subsequent license renewal and documented in a technical basis document. This is consistent with NUREG-2192 Section 2.1.3.1.1. Additional detail on the application of the 10 CFR 54.4(a)(1) scoping criterion is provided in Section 2.1.4.1.

2.1.3.3 10 CFR 54.4(a)(2) – Nonsafety-Related Affecting Safety-Related

Nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1) were included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2) requirements. A technical basis document was prepared to ensure complete and consistent application of this scoping criterion.

This subsequent license renewal scoping criteria requires consideration of the following:

- Nonsafety-related SSCs required to provide functional support for a safety-related 10 CFR 54.4(a)(1) function.
- Nonsafety-related systems directly connected to and providing structural support for a safety-related SSC.
- Nonsafety-related systems with a potential for spatial interaction with safety-related SSCs.

The first item is addressed by reviewing the FSAR and other CLB documents to identify nonsafety-related systems or structures required to support satisfactory accomplishment of a safety-related function. SSCs required for the system to perform its support function are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2). The remaining two items concern nonsafety-related systems with potential physical or spatial interaction with safety-related systems, structures, and components. Scoping of these systems is the subject of NEI 95-10, Appendix F (as referenced by NEI 17-01). To assure complete and consistent application of 10 CFR 54.4(a)(2) requirements and NEI 95-10, the technical basis document included a review of the CLB references relevant to functional interactions and describes the approach to scoping of nonsafety-related systems with a potential for physical or spatial interaction with safety-related SSCs. The preventive option, as described in NEI 95-10 Appendix F (as referenced by NEI 17-01), was chosen. The technical basis document provides guidance to ensure that subsequent license renewal scoping for 10 CFR 54.4(a)(2) met the requirements of the license renewal rule and NEI 17-01. Additional detail on the application of the 10 CFR 54.4(a)(2) scoping criterion is provided in Section 2.1.4.2.

2.1.3.4 10 CFR 54.4(a)(3) – Regulated Events

10 CFR 54.4(a)(3) requires that plant SSCs within the scope of subsequent license renewal include SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63). Technical basis documents were prepared to address subsequent license renewal scoping of SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection, environmental qualification, anticipated transients without scram, station blackout, and pressurized thermal shock. CLB documents were evaluated to identify the systems and structures that are relied upon to demonstrate compliance with each of these regulations. These technical basis documents are summarized below:

Fire Protection

10 CFR 54.4(a)(3) requires that SSCs relied on in safety analysis or plant evaluations to perform a function that demonstrates compliance with the regulations for fire protection (10 CFR 50.48) be included within the scope of subsequent license renewal.

The Fire Protection Rule, 10 CFR 50.48, requires the establishment of a fire protection plan (FPP) that satisfies GDC 3 and ensures the capability to safely shut down the plant.

The fire protection program meets the requirements of 10 CFR 50.48(c), which endorses, with exceptions, the National Fire Protection Association's (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants", 2001 Edition. The guidance of NEI 04-02, "Guidance for Implementing a Risk-Informed, Performance-Based Fire Protection Program under 10 CFR 50.48(c)," as endorsed by Regulatory Guide 1.205, "Risk-Informed, Performance Fire Protection for Existing Light-Water Nuclear Power Plants," was used. A Safety Evaluation was issued on February 11, 2015 by the NRC (ML14287A289), that transitioned the existing fire protection program to a risk-informed, performance-based program based on NFPA 805, in accordance with 10 CFR 50.48(c).

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

The fire detection and suppression systems are plant-wide systems that protect a wide variety of plant equipment. The portions of these systems that are not required to demonstrate compliance with 10 CFR 50.48 are not included within the scope of subsequent license renewal if (1) those portions of the system are provided to protect areas that do not contain any SSCs within the scope of subsequent license renewal and (2) those portions of the system can be isolated from the in-scope portions of the system. The isolation valve is included within the scope of subsequent license renewal.

Environmental Qualification

10 CFR 54.4(a)(3) requires that SSCs relied on in safety analysis or plant evaluations to perform a function that demonstrates compliance with the regulations for environmental qualification (10 CFR 50.49) be included within the scope of subsequent license renewal.

10 CFR 50.49 defines electric equipment important to safety that is required to be environmentally qualified to mitigate certain accidents that would result in harsh environmental conditions in the plant. The EQ program, which satisfies these requirements, controls the maintenance of the list of EQ components. An Equipment Qualification Database (EQDB) identifies electrical equipment which requires environmental qualification. The PAMS equipment database (discussed in Section 2.1.2.3) includes a field that identifies the EQ scoping status.

The EQ technical basis document provides a list of systems that include EQ components. These systems are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(3).

Pressurized Thermal Shock

10 CFR 54.4(a)(3) requires that SSCs relied on in safety analysis or plant evaluations to perform a function that demonstrates compliance with the regulations for pressurized thermal shock (10 CFR 50.61) be included within the scope of subsequent license renewal.

Pressurized Thermal Shock (PTS) is a potential pressurized water reactor (PWR) event or transient causing vessel failure due to severe overcooling (thermal shock) concurrent with, or followed by, significant pressure in the reactor vessel. The CLB shows that the reactor vessel has been demonstrated to meet the toughness requirements of 10 CFR 50.61 through its current 60-year end-of-license period. Eighty-year end-of-license fluence projections were prepared, and the components that are projected to meet the definition of beltline material after this time were identified.

The PTS technical basis document summarizes the results of a review of the current licensing basis with respect to pressurized thermal shock. The reactor vessel is included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(3) scoping criteria.

Anticipated Transients Without Scram

Criterion 10 CFR 54.4(a)(3) requires that SSCs relied on in safety analysis or plant evaluations to perform a function that demonstrates compliance with the regulations for anticipated transients without scram (10 CFR 50.62) be included within the scope of subsequent license renewal.

An anticipated transient without scram is an anticipated operational occurrence that is accompanied by a failure of the reactor trip function to shut down the reactor. The Anticipated Transients Without Scram (ATWS) rule, 10 CFR 50.62, requires improvements in the design and operation of light-water cooled water reactors to reduce the likelihood of failure to automatically shutdown the reactor following anticipated transients, and to mitigate the consequences of an ATWS event.

ATWS design criteria are described in FSAR Section 7.8, ATWS Mitigation System Actuation Circuitry (AMSAC). AMSAC consists of a diverse method to mitigate the consequences of an ATWS event by isolating steam generator blowdown and sample lines, initiating emergency feedwater, and initiating a turbine trip under conditions indicative of an ATWS.

The ATWS technical basis document summarizes the AMSAC and includes a list of systems and structures associated with AMSAC. SSCs classified as satisfying criterion 10 CFR 54.4(a)(3) related to ATWS are included within the scope of subsequent license renewal.

Station Blackout

Criterion 10 CFR 54.4(a)(3) requires that SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the regulations for station blackout (10 CFR 50.63) be included within the scope of subsequent license renewal.

10 CFR 50.63 requires that each light-water-cooled nuclear power plant be able to withstand, for a specified duration, and recover from a station blackout (SBO). An SBO is the loss of offsite and onsite AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO does not include the loss of available AC power to buses fed by station batteries through inverters or by alternate AC sources.

The objective of this requirement is to assure that nuclear power plants are capable of withstanding an SBO and maintaining adequate reactor core cooling and containment integrity for the specified duration. A four hour coping analysis has been developed to address the requirements of 10 CFR 50.63.

The offsite power supplies relied upon to recover from a station blackout are the two separate power sources supplying the Class 1E ES system, which is in compliance with General Design Criterion 17 and Regulatory Guide 1.32. The two separate power sources, which are considered the preferred power sources, are the Engineered Safety Features transformer XTF-4 and Emergency Auxiliary Transformer XTF-31. The offsite high-voltage source for these transformers are the 115 kV Parr ESF Line and 230 kV Bus #3.

Plant electrical system cables, and cable bus are routed from the Engineered Safety Features transformer XTF-4 and Emergency Auxiliary Transformer XTF-31 transformers to the ES 7.2kV Buses XSW-1DA, and XSW-1DB.

Offsite power is supplied to the station by the 115 kV Parr ESF Line and 230 kV Bus #3, to the Engineered Safety Features transformer XTF-4 and Emergency Auxiliary Transformer XTF-31 transformers. Restoration of the 7.2kV ES buses XSW-1DA, XSW-1DB, XSW-1EA, and XSW-1EB through the Engineered Safety Features transformer XTF-4 or Emergency Auxiliary Transformer XTF-31 would by definition terminate an SBO event. The following electrical components are in the scope of license renewal for recovery from Station Blackout:

- 230KV Bus #3 disconnect switches, circuit breakers, associated control components (including cables), transmission conductors, switchyard bus, high voltage insulators to connect the 230KV Bus #3 Breaker XCB-8892 to Emergency Auxiliary Transformer XTF-31.
- 115KV Parr ESF Line disconnect switches, circuit breakers, associated control components (including cables), voltage regulators, transmission conductors, switchyard bus, high voltage insulators to connect the 115 kV Parr ESF Line, Circuit Switcher XES4 to the Engineered Safety Features transformer XTF-4.
- The Emergency Auxiliary Transformer, XTF-31, connection to the 7.2kV bus XSW-1DX includes insulated cables, cable bus, and circuit breakers.
- The XTF-31 connection via the 7.2kV bus XSW-1DX to the 7.2kV ES buses XSW-1DA and XSB-1DB includes insulated cables, cable bus, and circuit breakers.
- The Engineered Safety Features transformer, XTF-4, connection to the 7.2kV ES buses XSW-1DA and XSB-1DB includes insulated cables, cable bus, and circuit breakers.
- ES bus XSW-1EA is connected to ES bus XSW-1DA with insulated cables, cable bus, and circuit breakers.
- ES bus XSW-1EB is connected to ES bus XSW-1DB with insulated cables, cable bus, and circuit breakers.
- DG/A (XEG-0001A-DG) is connected to ES bus XSW-1DA with insulated cables and circuit breakers
- DG/B (XEG-0001B-DG) is connected to ES bus XSW-1DB with insulated cables and circuit breakers

The Alternate AC (AAC) source of power from the Parr Hydro Power Station via ESF Transformer XTF5052 to bus XSW-1DX described in FSAR Section 8.1 is not credited for SBO recovery.

Recovery from an SBO event can be accomplished by restoration of the onsite emergency power supply (one of two emergency diesel generators (EDGs)). Restoration of one emergency diesel generator aligned to one ESF bus would supply sufficient power to bring the unit to safe shutdown, terminating the SBO event, which is the current SBO licensing basis. The following components are in the scope of subsequent license renewal for recovery from Station Blackout:

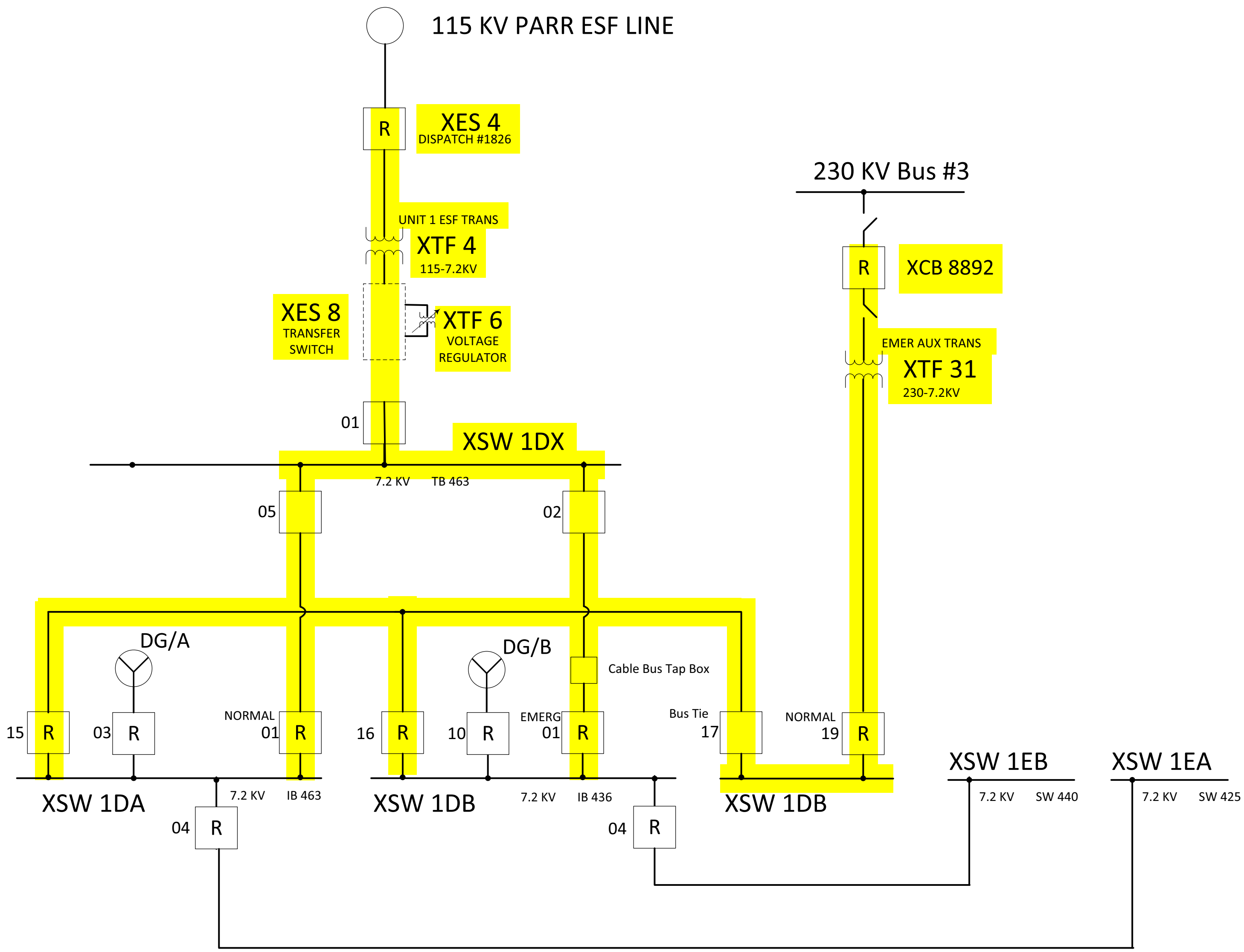
- Diesel generators ’A’ and B, and associated controls and support equipment.
- 7.2kV cables and circuit breakers connecting diesel generators ’A’ and ’B’ to 7.2kV ES buses XSW-1DA and XSW-1DB.
- 7.2kV ES buses XSW-1DA and XSW-1DB.

The SBO technical basis document summarizes the SBO coping and recovery requirements and includes a list of systems, structures, and components associated with SBO. SSCs classified as satisfying criterion 10 CFR 54.4(a)(3) related to SBO are included within the scope of subsequent license renewal.

The SBO offsite recovery paths are shown in Figure 2.1-1, SBO Offsite Recovery Paths.

Additional detail on the application of the 10 CFR 54.4(a)(3) scoping criteria is provided in Section 2.1.4.3.

Figure 2.1-1 SBO Offsite Recovery Paths



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2.1.4 SCOPING METHODOLOGY

The scoping process is the systematic process used to identify the systems, structures, and components within the scope of the license renewal rule. The scoping process was initially performed at the system and structure level, in accordance with the scoping criteria identified in 10 CFR 54.4(a). System and structure intended functions were identified from a review of the CLB and design basis documents. In-scope boundaries were established and documented in the scoping evaluations, based on the identified intended functions. The in-scope boundaries form the basis for identification of the in-scope components, which is the first step in the screening process described in Section 2.1.5. The system and structure scoping results are provided in Section 2.2.

The scoping process began with the development of a comprehensive list of plant systems and structures, as described in Section 2.1.3.1. The systems and structures were grouped into one of the following categories:

- Reactor Vessel, Internals and Reactor Coolant System
- Engineered Safety Features
- Auxiliary Systems
- Steam and Power Conversion Systems
- Containments, Structures, and Component Supports
- Electrical and Instrumentation and Controls

Each system and structure was scoped for subsequent license renewal using the criteria of 10 CFR 54.4(a). These criteria are briefly identified as follows:

- 10 CFR 54.4(a)(1) - Safety-related
- 10 CFR 54.4(a)(2) - Nonsafety-related affecting safety-related
- 10 CFR 54.4(a)(3) - Regulated Events:
  - Fire Protection (10 CFR 50.48)
  - Environmental Qualification (10 CFR 50.49)
  - Pressurized Thermal Shock (10 CFR 50.61)
  - Anticipated Transients Without Scram (10 CFR 50.62)
  - Station Blackout (10 CFR 50.63)

The application of each of these criteria is discussed in Section 2.1.4.1, Section 2.1.4.2, and Section 2.1.4.3 below.

2.1.4.1 Safety-Related – 10 CFR 54.4(a)(1)

In accordance with 10 CFR 54.4(a)(1), the systems, structures and components within the scope of subsequent license renewal include:

Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the following functions-

(i) The integrity of the reactor coolant pressure boundary;

(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in §50.34(a)(1), §50.67(b)(2), or §100.11 of this chapter, as applicable.

The safety-related plant components are identified in controlled engineering drawings and in the PAMS database. The safety-related classifications in the PAMS database were populated and maintained using a controlled procedure, with classification criteria consistent with the above 10 CFR 54.4(a)(1) criteria, as described in Section 2.1.3.2.

Safety-related classifications for systems and structures are based on the PAMS safety classification, system and structure descriptions and analyses in the FSAR, or on design basis documents such as engineering drawings, evaluations, or calculations. Systems and structures that are identified as safety-related in the FSAR or in design basis documents have been classified as satisfying the criteria of 10 CFR 54.4(a)(1) and have been included within the scope of subsequent license renewal. The associated piping and components included within the scope of subsequent license renewal are identified on the subsequent license renewal boundary drawings in blue.

Plant conditions required per SLR-SRP, including conditions of normal operation, internal events, anticipated operational occurrences, design basis accidents, external events, and natural phenomena as described in the CLB, were considered for subsequent license renewal scoping.

PAMS includes some components that are conservatively classified as safety-related, but which are not relied upon for completion of a safety-related function. Components classified as safety-related in the PAMS database that do not support a safety-related system function were evaluated as nonsafety-related for subsequent license renewal scoping. Over classifications that affected scoping include the following;

There are only five components in the Turbine Building that are classified as safety-related:

- Two turbine first stage pressure transmitters
- Three high pressure emergency electro-hydraulic trip fluid pressure switches.

A technical evaluation was prepared to evaluate the functions and failure modes of these instruments and concluded that they may fail in any manner without loss of a safety function. These are the only components within the Turbine Building that are classified as safety-related. As a result, nonsafety-related fluid containing components in the Turbine Building are outside the 10 CFR 54.4(a)(2) scoping criteria for their potential spatial interaction with those instruments.

2.1.4.2 Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)

In accordance with 10 CFR 54.4(a)(2), the systems, structures and components within the scope of subsequent license renewal include:

- Nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1)(i), (ii), or (iii).

This scoping criterion requires an assessment of nonsafety-related SSCs with respect to the following application or configuration categories:

- Functional support for safety-related SSC 10 CFR 54.4(a)(1) functions
- Connected to and provide structural support for safety-related SSCs
- Potential for spatial interactions with safety-related SSCs

Each of these categories is discussed below:

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

This category addresses non-safety-related SSCs that are required to function in support of a safety-related SSC intended function. The functional requirement distinguishes this category from the other categories, where the nonsafety-related SSCs are required only to maintain adequate integrity to preclude structural failure or spatial interactions.

The FSAR, CLB, system drawings, and other design basis documents were reviewed to identify nonsafety-related SSCs required to support satisfactory accomplishment of a safety-related function. Nonsafety-related SSCs credited in CLB documents to support a safety-related function have been included with the scope of subsequent license renewal. SSCs that are required to perform or support a safety-related function are classified as safety-related, with the following exceptions:

1. The integrity of nonsafety-related piping and piping components between the main steam isolation valves and downstream isolation valves (in main steam, extraction steam, gland steam, steam dump, and turbine cycle sampling systems) provides for main steam isolation for a steamline break coincident with failure of a main steam isolation valve.
2. The turbine electro-hydraulic system implements a turbine trip for alternate main steam isolation (the integrity of passive mechanical components is not needed for this function).

3. Nonsafety-related incore instrumentation isolation valves above the seal table provide for reactor coolant integrity (isolation) in the event of a thimble tube leak.
4. The miscellaneous drains system provides instrumentation trip signals to circulating water pumps and valves on detection of high water levels to mitigate internal flooding (the integrity of passive mechanical components is not needed for this function).
5. The nuclear drains system provides a flowpath to drain Reactor Building spray water from the reactor cavity.
6. The nuclear drains system provides instrumentation trip signals to feedwater pumps and valves on detection of high water levels to mitigate internal flooding the integrity of passive mechanical components is not needed for this function).
7. The miscellaneous drains and nuclear drains systems prevent the flow of steam between harsh and mild environment areas.
8. The fuel handling system reactor cavity seal ring provides a pressure boundary to retain inventory in the refueling cavity during refueling.
9. The feedwater system contains nonsafety-related venturis that develop delta-P used by safety-related instrumentation inputs to reactor trip logic.
10. The integrity of nonsafety-related portions of the emergency diesel generators air intake and exhaust piping supports diesel operation.
11. The integrity of nonsafety-related piping and components in the turbine driven emergency feedwater pump lubricating oil piping supports pump operation.

The nonsafety-related systems, or nonsafety-related portions of safety-related systems and structures that support the above functions, were included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2). Where they appear on subsequent license renewal boundary drawings, these functional nonsafety-related SSCs are highlighted in blue.

The next two 10 CFR 54.4(a)(2) scoping categories are the subject of NEI 95-10, Appendix F (as referenced in NEI 17-01). The guidance requires that, when demonstrating failures of nonsafety-related systems would not adversely impact the ability to maintain intended functions, a distinction must be made between nonsafety-related systems that are directly connected to safety-related systems and those that are not directly connected to safety-related systems. For a nonsafety-related piping system that is directly connected to and provides structural support for a safety-related piping system, the nonsafety-related piping and supports shall be included within the scope of subsequent license renewal up to (1) the analytical boundary defined in the CLB seismic analysis for the safety-related piping or, (2) if the seismic boundary is not clearly defined in the CLB information, up to and including the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions. The location of the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions is identified using the guidance presented in NEI 95-10, Appendix F, Section 4 (as referenced in NEI 17-01).

The methodology for identification of SSCs that satisfy the 10 CFR 54.4(a)(2) scoping criterion was based on a review of applicable CLB and design basis documents, as well as plant specific and industry operating experience.

Connected to and Provide Structural Support for Safety-Related SSCs

The guidance of NEI 95-10, Appendix F (as referenced in NEI 17-01) was used to identify the endpoints of nonsafety-related piping components that are directly attached to, and provide support for, safety-related piping components. The attached nonsafety-related piping components must be included within scope up to and including the first seismic or equivalent anchor. NEI 95-10, Appendix F (as referenced in NEI 17-01) lists the following configurations that correspond to this requirement:

1. A seismic anchor is defined as a device or structure that ensures that forces and moments are restrained in three orthogonal directions.
2. An equivalent anchor may be defined in the CLB and can be credited for the 10 CFR 54.4(a)(2) evaluation.
3. An equivalent anchor may also consist of a large piece of plant equipment (e.g., a heat exchanger) or a series of supports that have been evaluated as a part of a plant-specific piping design analysis to ensure that forces and moments are restrained in three orthogonal directions.
4. There may be isolated cases where an equivalent anchor for a particular piping segment is not clearly described within the existing CLB information or original design basis. In those instances, a combination of restraints or supports such that the NSR piping and associated structures and components attached to the safety-related piping is included in scope up to a boundary point that encompasses at least two supports in each of three orthogonal directions.

An alternative to specifically identifying a seismic anchor or equivalent anchor is to include enough of the nonsafety-related piping run to ensure that these anchors are included and thereby ensure the piping and anchor intended functions are maintained. The following methods provide assurance that the included piping encompasses the nonsafety-related piping included in the design basis seismic analysis and is consistent with the current licensing basis:

a. A base-mounted component (e.g., pump, heat exchanger, tank, etc.) that is a rugged component and is designed not to impose loads on connecting piping. The subsequent license renewal scope should include the base-mounted component as it has a support function for the safety-related piping.

b. A flexible connection is considered a pipe stress analysis model end point when the flexible connection effectively decouples the piping systems (i.e., does not support loads or transfer loads across it to connecting piping).

c. A free end of nonsafety-related piping.

d. For nonsafety-related piping runs that are connected at both ends to safety-related piping include the entire run of nonsafety-related piping.

e. A point where the buried piping exits the ground. The buried portion of the piping should be included in the scope of subsequent license renewal. There are no areas at the site with buried piping in which the soil is subject to liquefaction.

f. A smaller branch line where the moment of inertia ratio of the larger piping to the smaller piping is equal to or greater than the acceptable ratio defined by the current licensing basis (16.7), because significantly smaller piping does not impose loads on larger piping and does not support larger piping.

These scoping boundaries are determined from review of the physical installation details, design drawings, plant-specific piping analyses, or seismic analysis calculations.

Failure in nonsafety-related piping beyond the above anchor locations would not impact structural support for the safety-related piping. The associated piping and components included within the scope of subsequent license renewal are identified on the subsequent license renewal boundary drawings in orange. Symbols identifying the anchor locations and the CLB seismic analysis boundaries (or support boundaries) that define the structural support boundary for safety-related piping systems are shown on the subsequent license renewal boundary drawings. Note that if the connected nonsafety-related piping system contains water, steam, or oil, then the in-scope boundary may extend beyond the locations described above due to potential for spatial interaction with safety-related SSCs.

Potential for Spatial Interactions with Safety-Related SSCs

Nonsafety-related systems that are not connected to safety-related piping or components, or are outside the structural support boundary for the attached safety-related piping system, and have a spatial relationship such that their failure could adversely impact the performance of a safety-related SSC intended function, must be included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2) requirements. As described in NEI 95-10, Appendix F, there are two options when performing this scoping evaluation: a mitigative option and a preventive option.

The mitigative option involves crediting plant mitigative features to protect safety-related SSCs from failures of nonsafety-related SSCs. Examples of plant mitigative features include pipe whip restraints, jet impingement shields, spray and drip shields, seismic supports, flood barriers, and physical barriers (e.g., floors, interior walls, doors, dampers). This option requires a demonstration that the mitigating features are adequate to protect safety-related SSCs from failures of nonsafety-related SSCs regardless of failure location. If this level of protection can be demonstrated, then only the mitigative features need be included within the scope of subsequent license renewal. Mitigative plant design features within structures are not used to exclude SSCs from the scope of subsequent license renewal, although mitigative features are included within the scope of subsequent license renewal.

The preventive option involves identifying the nonsafety-related SSCs that have a spatial relationship such that failure could adversely impact the performance of a safety-related SSC intended function and including the identified nonsafety-related SSC within the scope of subsequent license renewal without consideration of plant mitigative features.

The preventive option for 10 CFR 54.4(a)(2) scoping was applied. The preventive option, as implemented, is based upon a “spaces” approach for determining potential for spatial interactions with safety-related SSCs. The boundaries for the “spaces” are structure boundaries (typically the outer walls defining an entire structure) that act as physical barriers and separate safety-related targets from nonsafety-related hazards.

Nonsafety-related piping and components that contain water, oil, or steam are not excluded from scope unless it can be demonstrated that they are not in proximity to safety-related SSCs. This is demonstrated by confirming that there are no safety-related SSCs located within the same space (e.g., structure or enclosure) as the nonsafety- related piping or component containing water, oil, or steam. This demonstration is based on confirming that there are adequate physical barriers (e.g., structural boundaries) separating the nonsafety-related piping or component from safety-related SSCs, thereby preventing the potential spatial interaction. The structural barrier components are included in scope. No credit is taken for separation by distance alone without a physical barrier capable of preventing the spatial interaction.

Potential spatial interaction is assumed for nonsafety-related SSCs that contain water, oil, or steam and that are located within structures that contain safety-related SSCs that are relied upon to perform safety-related functions. The structures of concern for potential spatial interaction were identified based on a review of the CLB to determine which structures contained active or passive safety-related SSCs. It is assumed that nonsafety-related SSCs within structures containing safety-related SSCs may be located in proximity to safety-related SSCs. As described in Section 2.1.4.1, the components within the Turbine Building that are classified as safety-related may fail without loss of a safety function, so the Turbine Building is treated as if it does not contain safety-related components for this scoping criterion.

Nonsafety-related piping and components that contain water, oil, or steam, and are located inside structures that contain safety-related SSCs, are included within the scope of subsequent license renewal for potential spatial interaction in accordance with the requirements of criterion 10 CFR 54.4(a)(2), as recommended by NEI 95-10, Appendix F. Components that retain only a small quantity of unpressurized lubricating oil needed for a small oil bath or slinger ring (such as small pumps for which an oil system is not depicted on system drawings) are not expected to be capable of spatial interactions that could cause loss of a safety-related function. Oil subsystems (e.g., on pumps) that include a pump, piping, valves, and/or heat exchanger are included within scope. High- energy lines located within structures that contain safety-related equipment are included within the scope of subsequent license renewal, in accordance with 10 CFR 54.4(a)(1) or (a)(2), depending on their safety classification. Safety-related high energy lines are in scope in accordance with 10 CFR 54.4(a)(1), and nonsafety-related high-energy lines are in scope in accordance with 10 CFR 54.4(a)(2). Potential spatial interaction due to leakage or spray is assumed for system pressure as low as atmospheric. Supports for nonsafety-related SSCs within these structures are included in scope.

Air and gas systems (non-liquid) are not a hazard to other plant equipment, and do not have potential for spatial interactions with safety-related SSCs. SSCs containing air or gas cannot adversely affect safety-related SSCs due to leakage or spray, since gas systems contain no liquids that could spray or leak onto safety-related systems to cause shorts or other malfunctions. Plant-specific operating experience was reviewed and confirmed that there have been no failures due to aging in systems containing air or gas that have adversely impacted the accomplishment of a safety-related function. Additionally, air and gas systems are classified as moderate energy systems. As described in NEI 95-10, Appendix F, paragraph 5.2.2.2.2, physical impact from pipe whip or jet impingement from moderate energy systems do not occur and need not be considered. Thus, the nonsafety-related systems containing air or gas are not included within the scope of subsequent license renewal for spatial interaction. The supports are included in scope to prevent the nonsafety-related piping from falling and potentially impacting safety-related SSCs.

The piping components included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2) for potential spatial interaction with safety-related SSCs are highlighted on the subsequent license renewal boundary drawings in orange.

Scoping of Abandoned Mechanical Components

There are mechanical fluid components that have been abandoned. Abandoned piping components within structures containing safety-related components were excluded from scope when the following conditions were met:

1. The abandoned piping components do not provide structural or seismic support to attached safety-related piping, and
2. The abandoned piping is separated from sources of water by blanks, blind flanges or pipe caps. Closed valves are not credited to keep fluid from abandoned components, and
3. The abandoned piping is empty of fluid. Piping was verified to be empty by establishing configuration (such as the piping being open-ended at the low point), by review of documents that abandoned the equipment, or by ultrasonic testing or other method that is capable of confirming the absence of trapped fluid.

If the above conditions are not met, the abandoned systems or portions thereof are included within the scope of LR for aging management. Abandoned equipment is not relied on to perform any function delineated in 10 CFR 54.4(a)(1) or (a)(3) as it is non-operational.

2.1.4.3 Regulated Events – 10 CFR 54.4(a)(3)

In accordance with 10 CFR 54.4(a)(3), the systems, structures, and components within the scope of subsequent license renewal include:

> *All systems, structures and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).*

For each of the five regulations, a technical basis document was prepared to provide input into the scoping process. Each of the regulated event technical basis documents (described in Section 2.1.3.4) identify the systems and structures that are relied upon to demonstrate compliance with the applicable regulation. The technical basis documents also identify the source documentation used to determine the scope of components within the system that are credited to demonstrate compliance with each of the applicable regulated events. Guidance provided by the technical basis documents was incorporated into the system and structure scoping evaluations, to determine the SSCs credited for each of the regulated events. SSCs credited in the regulated events have been classified as satisfying criteria of 10 CFR 54.4(a)(3) and have been included within the scope of subsequent license renewal.

The piping components included within the scope of subsequent license renewal for performing a function that demonstrates compliance with a regulated event specified in 10 CFR 54.4(a)(3) are highlighted on the subsequent license renewal boundary drawings in blue.

2.1.4.4 System and Structure Intended Functions

For the systems and structures within the scope of subsequent license renewal, the intended functions that are the bases for including them within the scope of subsequent license renewal are identified and documented in the scoping evaluation. The system or structure intended functions are based on the applicable CLB reference documents. For systems, the system level intended function descriptions associated with 10 CFR 54.4(a)(1) are consistent with the categories of nuclear safety criteria for pressurized water reactors as documented in industry standard ANSI/ANS-51.1-1983, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants” (Reference 1.7-14), to provide for consistent function application and appropriate level of detail for system level intended function descriptions. The component level intended functions are the passive component functions that are necessary to support the system or structure intended function(s). The structure and component intended functions are further described in Section 2.1.5.2.

2.1.4.5 Scoping Boundary Determination

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

Mechanical Systems

For mechanical systems, the mechanical components that support the system intended functions are included within the scope of subsequent license renewal and are depicted on the applicable system piping and instrumentation diagram. Mechanical system piping and instrumentation diagrams are marked up to create subsequent license renewal boundary drawings showing the in-scope, passive components. Components that are not long-lived are identified on the drawings with notes. Components that are required to support a safety-related function (both safety-related and nonsafety-related components), or a function that demonstrates compliance with one of the subsequent license renewal regulated events are identified on the system piping and instrumentation diagrams by blue highlighting. Nonsafety-related components that are connected to safety-related components and are required to provide structural support at the safety/nonsafety interface, or components whose failure could prevent satisfactory accomplishment of a safety-related function due to spatial interaction with safety-related SSCs, are identified by orange highlighting. Drawings identify the system with which they are primarily associated. In-scope, passive components from a different system, whose primary depiction is on another drawing, are highlighted in gray. A download of associated system components from PAMS confirms the scope of components in the system. Plant walkdowns were performed when required for additional confirmation.

Structures

For structures, the structural components that are required to support the intended function(s) of the structure are included within the scope of subsequent license renewal. The structural components are identified from a review of applicable plant design drawings of the structure, applicable FSAR sections, and design basis documentation. Reviews of mechanical and electrical subsequent license renewal scoping documents were performed to ensure that structures and structural components required to support in-scope mechanical and electrical SSCs were included in the structural scope. Plant walkdowns were performed when required for additional confirmation. Structural bolting required to support the structure proper is evaluated with the structure. Structural bolting associated with a component support or a structural commodity component is evaluated with the component support or structural commodity components.

Electrical

A list of electrical and instrumentation and control (I&C) systems was developed and the systems were scoped against the criteria of 10 CFR 54.4(a). The list of electrical and I&C systems and the results of the scoping are provided in Table 2.2-1.

<u>System Level Scoping</u>

At the system level, the scoping methodology utilized for electrical and I&C systems was similar to the mechanical system-level scoping. Electrical and I&C systems were identified from PAMS by system designation code. The FSAR descriptions, CLB documents and design basis documents applicable to each system were reviewed to determine the system safety classification and to identify the system functions. System level functions were evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The results of the system level scoping along with a list of references supporting the evaluation of each electrical and instrumentation and control system were documented.

Component Level Scoping

Components of electrical and I&C systems that were determined to be within scope of subsequent license renewal, and electrical and I&C components within mechanical systems that were determined to be within scope of subsequent license renewal, did not require evaluation to determine which components were required to perform or support the identified intended functions. A bounding scoping approach was used for electrical and I&C components. Electrical and I&C components within in-scope systems were included within the scope of subsequent license renewal. In-scope electrical and I&C components were placed into commodity groups and were evaluated as commodities during the screening process as described in Section 2.1.5.1.

Structural components which support or interface with electrical components, such as structural supports, cable trays, conduits, instrument racks, panels and enclosures, are evaluated as structural components.

Unlike mechanical systems, individual subsequent license renewal boundary drawings were not created for each electrical and I&C system.

2.1.5 SCREENING PROCEDURE

Once the SSCs within the scope of subsequent license renewal have been determined, the next step is to determine which structures and components are subject to an aging management review.

2.1.5.1 Identification of Structures and Components Subject to AMR

The requirement to identify structures and components subject to an aging management review is specified in 10 CFR 54.21(a)(1), which states:

(a) An integrated plant assessment (IPA). The IPA must -

(1) For those system, structures, and components within the scope of this part, as delineated in §54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components -

(i) That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

(ii) That are not subject to replacement based on a qualified life or specified time period.

Structures and components that perform an intended function without moving parts or without a change in configuration or properties are defined as passive for subsequent license renewal. Passive structures and components that are not subject to replacement based on a qualified life or specified time period are defined as long-lived for subsequent license renewal. The screening procedure is the process used to identify the passive, long-lived structures and components within the scope of subsequent license renewal. These structures and components are subject to aging management review.

NUREG-2192, Table 2.1-6 and NEI 95-10, Appendix B, were used as the basis for the identification of passive structures and components, as recommended by NEI 17-01, Section 1.1. Most passive structures and components are long-lived. Boundary drawing notes identify the cases where a passive component is determined not to be long-lived.

Structures and components subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.21(a)(1) described above. The process implemented to meet these requirements for mechanical systems, structures, and electrical commodities is described as follows:

Mechanical Systems

The mechanical system screening process began with the results from the scoping process. For in-scope mechanical systems, the written descriptions and marked up system piping and instrumentation diagrams clearly identify the in-scope system boundary of passive components for subsequent license renewal. The marked up system piping and instrumentation diagrams are called subsequent license renewal boundary drawings. These system boundary drawings were reviewed to identify the passive, long-lived components, and the identified components were entered into the subsequent license renewal database. Component listings from PAMS were also reviewed to confirm that system components were considered during the process. In cases where the system piping and instrumentation diagram did not provide sufficient detail, such as for some large vendor supplied components (e.g., chillers, emergency diesel generators), the associated component drawings or vendor manuals were also reviewed. Plant walkdowns were performed when required for confirmation. Short-lived components were excluded from aging management review. The bases for their exclusion were documented and notes were added to the system boundary drawings to identify their status.

A complex assembly is a predominantly active assembly where the performance of its components is closely linked to that of the intended function of the entire assembly, such that testing and monitoring of the assembly is sufficient to identify degradation of these components. Examples of complex assemblies include diesel generators and chiller units. Complex assemblies are considered active and can be excluded from the requirements of AMR. However, to the extent that complex assemblies include piping or components that interface with external equipment, or components that cannot be adequately tested or monitored as part of the complex assembly, those components are identified and subject to aging management review. This follows the screening methodology for complex assemblies as described in Table 2.1-2 of NUREG-2192.

Note that safety-related air operated valves normally fail to their safety position. For these components, the supply of compressed air does not support the system intended function. Safety-related components such as solenoid valves whose only function is to vent the air from these valve operators are within scope, but the function is performed by active internal components, and the passive pressure boundary of the valve body or piping components does not contribute to the safety-related function. Therefore, these components are not subject to aging management review.

Mechanical components are screened with the system in which they were scoped. For heat exchangers, the entire heat exchanger is evaluated within the system in which it is identified in PAMS.

Structures

Structures and structural components typically perform their functions without moving parts and without a change in configuration or properties. When a structure or structural component was determined to be within the scope of subsequent license renewal by the scoping process described in Section 2.1.4.5, the structure screening methodology classified the component as active or passive. Active components do not require aging management. This is consistent with guidance found in NEI 95-10, Appendix B, as referenced by NEI 17-01. During the structure screening process, the intended function(s) of passive structural components were documented. In the structure screening process, an evaluation was made to determine whether in-scope structural components were subject to replacement based on a qualified life or specified time period. If an in-scope structural component was determined to be subject to replacement based on a qualified life or specified time period, the component was identified as short-lived and was excluded from an AMR. In such a case, the basis for determining that the structural component was short-lived was documented.

Electrical Commodities

Screening of electrical and I&C components within the in-scope electrical, I&C, and mechanical systems used a bounding approach as described in NEI 17-01 (Reference 1.7-4). Electrical and I&C components for the in-scope systems were assigned to commodity groups based on the listing in NUREG-2192, Table 2.1-6. Commodities subject to an aging management review were identified by applying 10 CFR 54.21(a)(1) to identify those commodities that perform their function without moving parts or a change in configuration ("passive" components). This method provides the most efficient means for determining the electrical commodities subject to an aging management review since many electrical and I&C components are active. Passive commodity groups were reviewed, and any that did not perform an intended function were determined to not require an aging management review. The remaining passive commodity groups were screened consistent with 10 CFR 54.21(a)(1)(ii) to exclude those commodities that are subject to replacement based on a qualified life or specific time period from the requirements of an aging management review. The remaining passive commodities were determined to be subject to aging management review. The electrical commodities that require an aging management review are identified in Section 2.5.

2.1.5.2 Intended Function Definitions

The intended functions that the components and structures must fulfill are those functions that are the bases for including them within the scope of subsequent license renewal. A component intended function is defined as a passive component function that must be performed in order for the system or structure to be able to perform the system or structure intended function(s). For example, pressure boundary failure of a component would cause loss of inventory from the system, and the system would subsequently be unable to perform its intended function(s). Structures and components may have multiple intended functions. Multiple intended functions have been considered, where applicable, consistent with the staff guidance provided in Table 2.1-3 of NUREG-2192.

Table 2.1-1 provides expanded definitions of structure and component passive intended functions identified in this application.

Table 2.1-1 Passive Structure and Component Intended Function Definitions

Intended Function Abbreviation	Intended Function
AN	Absorb neutrons.
BWI	Water barrier: Provides barrier to contain water inventory.
CE	Conducts electricity: Provides electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.
EN	Enclosure protection: Provides enclosure, shelter and/or protection for in-scope equipment (including radiation shielding and pipe whip restraint).
FB	Fire barrier: Provides rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant.
FD	Flow distribution: Provides for flow distribution to or from a desired component or area.
FLB	Flood barrier: Provides a protective barrier for internal/external flood events.
FLT	Filtration: Provides filtration.
HT	Heat transfer: Provides for heat transfer.
IN	Insulate: Provides electrical insulation.
JIS	Jet impingement shield. Provides jet impingement shielding for high-energy line breaks.
LB	Leakage boundary (spatial): Nonsafety-related component that maintains mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs. This function includes providing structural support to safety-related components, where applicable.
LTC	Limit thermal cycling: Limits thermal cycling (thermal sleeves).
MB	Missile barrier: Provides a missile (internal/external) barrier.
MCI	Coating integrity: Maintains coating integrity to prevent clogging of the emergency core cooling systems.
PB	Pressure boundary: Provides pressure boundary for delivery of sufficient flow at adequate pressure, or control room pressure boundary integrity, or containment integrity.
RF	Restricts flow: Provides flow restriction.
SCW	Source of cooling: Provides a source of cooling water for plant shutdown.
SI	Structural integrity (attached): Nonsafety-related component that maintains mechanical and structural integrity to provide structural support to attached safety-related piping and components.
SP	Spray pattern: Provides a spray pattern.
SS	Structural support: Provides structural and/or functional support to safety-related and/or nonsafety-related components.
TI	Thermal insulation: Provides thermal insulation.

2.1.5.3 Stored Equipment

Stored equipment that has a PAMS component entry is evaluated with the applicable system. Some equipment not in PAMS is staged for use by the Fire Brigade, such as smoke ejectors and ventilation trunks, but is not relied upon for fire protection or safe shutdown. Other fire-fighting equipment, such as extinguishers, air packs and fire hoses are addressed as consumables.

There are a small number of components stored for use to achieve safe shutdown following a fire. This equipment consists of cabling and cable lugs of various gauges, air or nitrogen bottles, valves, and air hoses (for manual operation of air-operated valves). These components are within the scope of subsequent license renewal and are subject to aging management review. The cabling and cable lugs are evaluated with the electrical equipment and the air bottles, valves, and hoses are evaluated with the instrument air system.

2.1.5.4 Consumables

The evaluation process for consumables is consistent with the guidance provided in NUREG-2192, Table 2.1-3. Consumables have been divided into the following four (4) groups for the purpose of subsequent license renewal: (a) packing, gaskets, component seals, and O-rings; (b) structural sealants; (c) oil, grease, and components filters; and (d) system filters, fire extinguishers, fire hoses, and air packs.

- Group (a) subcomponents (packing, gaskets, component seals, and O-rings): Managing loss of leak tightness due to degraded packing, gaskets, component seals, and O-rings for the pressure boundary and leakage boundary intended functions is not required. It is unlikely that leakage from packing, gaskets, component seals, and O-rings would result in failure of the system to deliver sufficient flow at adequate pressure. In regard to leakage, tours of the operating spaces are routinely conducted. When leakage is detected it is entered into the Corrective Action Program. The leakage is corrected by replacing the packing, gaskets, component seals, and O-rings as consumables. Therefore, these subcomponents are not subject to aging management review.
- Group (b) structural sealants: Aging management reviews were required for structural sealants in structures within the scope of subsequent license renewal. A summary of the AMR Results is presented in Section 3.5.
- Group (c) subcomponents (oil, grease, and component filters): These subcomponents are short-lived and are periodically replaced. Various plant procedures are used in the replacement of oil, grease, and filters in components that are in scope for subsequent license renewal. Therefore, these subcomponents are not subject to an aging management review.

- Group (d) consumables (system filters, fire extinguishers, fire hoses, and air packs): System filters are replaced in accordance with plant procedures based on vendor manufacturers' requirements and system testing. Fire extinguishers, self-contained breathing air packs, and fire hoses are within the scope of subsequent license renewal but are not subject to aging management because they are replaced based on condition. These components are periodically inspected in accordance with NFPA 10 for portable fire extinguishers, 29 CFR 1910.134 for self-contained breathing air packs, and NFPA 1962 for fire hoses. These standards require replacement of equipment based on their condition or performance during testing and inspection. These components are subject to replacements implemented by controlled procedures and are therefore not long-lived and not subject to aging management review.

2.1.6 INTERIM STAFF GUIDANCE DISCUSSION

As discussed in NEI 17-01, the NRC has encouraged applicants to address Subsequent License Renewal Interim Staff Guidance (SLR-ISG) documents in the Subsequent License Renewal Applications (SLRA). The following draft SLR-ISGs have been issued for use:

• SLR-ISG-2021-01-PWRVI (ML20217L203)	Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors of Subsequent License Renewal Guidance
• SLR-ISG-2021-02-MECHANICAL (ML20181A434)	Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance (including errata update)
• SLR-ISG-2021-03-STRUCTURES (ML20181A381)	Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance
• SLR-ISG-2021-04-ELECTRICAL (ML20181A395)	Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance

The following sub-sections provide summaries of how each of the SLR-ISGs are addressed in the SLRA.

2.1.6.1 Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors of Subsequent License Renewal Guidance (SLR-ISG-2021-01-PWRVI)

The guidance document changes issued in SLR–ISG–2021–01–PWRVI are based on the updated inspection and evaluation guidelines in Electric Power Research Institute (EPRI) Materials Reliability Program Topical Report No. 3002017168, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A),” issued June 2020, which the NRC staff found acceptable for referencing in licensing applications in its safety evaluation dated April 25, 2019, and approved for use in the staff’s letters to the EPRI Materials Reliability Program dated February 19, 2020, and July 7, 2020. The NRC issued SLR–ISG–2021–01–PWRVI to accomplish the following five objectives:

1. GALL-SLR Report and SRP-SLR guidance changes: Update the staff’s guidance for PWR reactor vessel internal components in the GALL-SLR Report and SRP-SLR to account for changes in inspection and evaluation criteria for PWR reactor vessel internal components made in MRP-227, Revision 1-A, and in other relevant industry documents (e.g., EPRI Materials Reliability Program expert panel reports for 80-year reactor vessel internals component assessments or in relevant industry interim guidance documents or alert letters).
2. Clarification on the use of MRP-227, Revision 1-A: Clarify whether incorporation and adoption of MRP-227, Revision 1-A, may be used as the starting basis for the PWR Reactor Vessel Internals program (Section B2.1.7) and whether reference to the criteria in MRP-227, Revision 1-A, in a PWR applicant’s SLRA will need to be subject to the performance of a reactor vessel internal component-specific gap analysis.
3. Reduction of unnecessary burden for PWR SLRAs: Provide additional clarifications on PWR Reactor Vessel Internals program (Section B2.1.7) programmatic change bases that are considered to be administrative and that will no longer need to be within the scope of AMP-identified exceptions or enhancements.
4. Resolution of applicant/licensee action items: Resolve whether the staff's applicant/ licensee action items in its safety evaluation for the inspection and evaluation guidelines in EPRI Topical Report 1022863, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A),” dated December 16, 2011, and applicant/licensee action item Number 1 in the staff's safety evaluation for the inspection and evaluation guidelines in MRP-227, Revision 1-A, dated April 25, 2019, need to be addressed in an initial LRA or an SLRA.
5. Closure of Regulatory Information Summary (RIS) 2011-07: Provide the staff's basis for closing previous guidance matters raised in RIS 2011-07, “License Renewal Submittal Information for Pressurized Water Reactor Internals Aging Management,” dated July 21,2011.

The SLRA incorporates the guidance presented in this SLR-ISG.

2.1.6.2 Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance (SLR-ISG-2021-02-Mechanical)

This SLR-ISG provides interim guidance to subsequent license renewal applicants for the following NUREG-2191 and NUREG-2192 Sections:

- X.M2, Neutron Fluence Monitoring

  The AMP is revised to reference approaches that have been found to be acceptable in recent staff reviews of extended beltline and reactor vessel internals fluence calculations, as RG 1.190 is not applicable. The Neutron Fluence Monitoring program (Section B3.2) incorporates the guidance presented in this SLR-ISG.

- XI.M2, Water Chemistry

  The AMP and FSAR Supplement are revised to include the latest revision of EPRI guidelines for PWRs. The Water Chemistry program (Section B2.1.2) and FSAR Supplement (Section A1.2) incorporate the guidance presented in this SLR-ISG.

- XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

  The AMP was revised to add the 2019 Edition of ASME Code, Section XI, Non-mandatory Appendix C, which provides flaw evaluation procedures for CASS with ferrite content $\geq$ 20 percent. The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel program (Section B2.1.6) incorporates the guidance presented in this SLR-ISG.

- XI.M21A, Closed Treated Water System

  The AMP was revised to include the latest revision of EPRI closed cooling water chemistry guidelines. The Closed Treated Water System program (Section B2.1.12) incorporates the guidance presented in this SLR-ISG.

- XI.M26, Fire Protection

  The SLR-ISG adds new fire barrier AMR Items VII.G.A-805, VII.G.A-806, and VII.G.A-807 to NUREG-2191, Table VII.G, “Fire Protection” and makes conforming changes to NUREG-2192, Table 3.3-1. AMR lines have been provided in Section 3.5, Aging Management of Containment, Structures, and Component Supports.

- NUREG-2191 Table VII.H2, Emergency Diesel Generator System

  The SLR-ISG revises NUREG-2191, Table VII.H2 “Emergency Diesel Generator System” and makes conforming changes to NUREG-2192, Table 3.3-1 to include line items to manage the reduction of heat transfer for a steel heat exchanger radiator exposed internally to diesel fuel oil and include a line item for managing loss of material for nickel alloy externally exposed to diesel fuel oil. Those material/ environment/ aging effect combinations are not present, so the associated SLR-ISG guidance is not applicable.

- XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

  The AMP was revised to recommend opportunistic inspections, in lieu of periodic inspections, as an acceptable alternative for buried internally coated/lined fire water system piping if certain conditions are met. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (Section B2.1.29) incorporates the guidance presented in this SLR-ISG-2021-02- Mechanical)

2.1.6.3 Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance (SLR-ISG-2021-03-Structures)

This SLR-ISG provides interim guidance to subsequent license renewal applicants for the following NUREG-2191 and NUREG-2192 Sections:

- XI.S8, Protective Coating Monitoring and Maintenance

  The AMP revises the frequency of inservice coating inspection monitoring to no later than 6 years based on trending of the total amount of permitted degraded coatings. The Protective Coating Monitoring and Maintenance program (Section B2.1.37) incorporates the guidance presented in this SLR-ISG.

- NUREG-2192 Section 3.5 (Fatigue Waiver)

  An option is provided to perform a further evaluation based on ASME Code, Section III, Division 1, Subsection NE, fatigue waiver analysis for containment metallic pressure-retaining boundary components that are subject to cyclic loading but have no current licensing basis (CLB) fatigue analysis. If the ASME Code fatigue waiver acceptance criteria are met then cracking due to cyclic loading does not require aging management. Further evaluation is provided in Section 3.5, Aging Management of Containment, Structures and Component Supports.

- NUREG-2192 Section 3.5 (Plant-Specific Aging Management Options)

  NUREG-2191 Chapters II and III and NUREG-2192, Table 3.5-1 are modified to reflect the option of using plant-specific enhancements to GALL-SLR XI.S2 and XI.S6 AMPs to manage the effects of aging in concrete in lieu of recommended plant-specific aging management programs. Further evaluation and AMR lines are provided in Section 3.5, Aging Management of Containment, Structures and Component Supports.

2.1.6.4 Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance (SLR-ISG-2021-04- Electrical)

This SLR-ISG provides interim guidance to subsequent license renewal applicants for the following NUREG-2191 and NUREG-2192 Sections:

- XI.E3A/B/C, Electrical Insulation for Inaccessible Medium Voltage/Instrument and Control/Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

  The AMPs are revised to allow 5-year inspections of manholes with water level monitoring and alarms. In addition, there is no need for event-driven inspections if there is no water accumulation in the manholes. The Electrical Insulation for Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (Section B2.1.40), Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (Section B2.1.41), and Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (Section B2.1.42) incorporate the guidance presented in this SLR-ISG.

- XI.E7, High Voltage Insulators

  The AMP is revised to add polymer and toughened glass high-voltage insulators to the scope and program elements and include all insulators operating at or above medium voltage. The High Voltage Insulators program (Section B2.1.45) incorporates the guidance presented in this SLR-ISG.

2.1.7 GENERIC SAFETY ISSUES

In accordance with the guidance in NEI 17-01 and Appendix A.3 of NUREG-2192, review of NRC generic safety issues (GSIs) as part of the subsequent license renewal process is required to satisfy 10 CFR 54.29. GSIs designated as unresolved safety issues (USIs) and high- and medium-priority issues in NUREG-0933, Appendix B, that involve aging effects for structures and components subject to an aging management review or time-limited aging analysis evaluation are to be addressed in the LRA. A review of the version of NUREG-0933 current six months prior to the subsequent license renewal application submittal, including the applicable Generic Issue Management Control System Report, determined that there were no outstanding USIs, or high- or medium-priority GSIs. The GSIs noted below were reviewed to assure they did not involve aging effects for structures and components subject to an aging management review or time-limited aging analysis evaluation:

- GSI-186, Potential Risk and Consequences of Heavy Load Drops in Nuclear Power Plants – This GSI addresses heavy load issues related to crane design and operation. Aging effects are not central to these issues. The issue does not involve time limited aging analysis evaluations. This issue is now closed (Reference ML113050589).
- GSI-189, Susceptibility of Ice Condenser Containments to Early Failure from Hydrogen Combustion during a Severe Accident – This GSI is not applicable, since there are no ice condenser containments. This issue is now closed (Reference ML13190A244).
- GSI-191, Assessment of Debris Accumulation on PWR Sump Performance – This GSI addresses the potential for blockage of containment sump strainers that filter debris from cooling water supplied to the safety injection and containment spray pumps following a postulated LOCA. The issue is based on the identification of new potential sources of debris, including failed containment coatings, which may block the sump strainers. The containment sump strainers are evaluated with the safety injection system as described in Section 2.3.2.4. The protective coatings inside containment are evaluated with the Reactor Building as described in Section 2.4.1.1. The issue is not related to the 60-year term of the current operating license; and, therefore, it is not a TLAA.
- GSI-193, BWR ECCS Suction Concerns – This GSI addresses the possible failure of low pressure emergency core cooling systems due to unanticipated, large quantities of entrained gas in the suction piping from the pressure suppression chamber (torus) in BWR Mark I containments. This issue is not applicable since the reactor is a PWR. This issue is closed (Reference ML16082A288).

- GSI-199, Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States – This GSI addresses how current estimates of the seismic hazard level at some nuclear sites in the central and eastern United States might be higher than the values used in their original designs and previous evaluations. Aging effects are not central to this issue. This issue does not involve time-limited aging analyses. Activities associated with this issue are covered by 10 CFR 50.54(f) Japan Near Term Task Force (NTTF) Recommendations.
- GSI-204, Flooding of Nuclear Power Plant Sites Following Upstream Dam Failures – This GSI addresses the potential flooding effects from upstream dam failure(s) on nuclear power plant sites, spent fuel pools, and sites undergoing decommissioning with spent fuel stored in spent fuel pools. Aging effects are not central to this issue. This issue does not involve time-limited aging analyses. Activities associated with this issue are covered by 10 CFR 50.54(f) Japan Near Term Task Force (NTTF) Recommendations.

NUREG-0933 was reviewed and there are no new generic issues that involve issues related to subsequent license renewal aging management reviews or TLAAs.

2.1.8 CONCLUSION

The scoping and screening methodology described above was used to identify the systems and structures that are within the scope of subsequent license renewal and to identify those structures and components that are subject to an aging management review. The methods are consistent with and satisfy the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2 PLANT-LEVEL SCOPING RESULTS

Table 2.2-1 lists the systems, structures and commodity groups that were evaluated to determine if they were within the scope of license renewal, using the methodology described in Section 2.1. A reference to the section of the application that contains the scoping and screening results is provided for each in-scope mechanical system, structure and commodity group in the Table. For electrical systems, a relevant FSAR reference is provided, if one exists.

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference[1]
Reactor Vessel, Internals, and Reactor Coolant System			
Reactor Vessel	N/A	Yes	2.3.1.1
Reactor Vessel Internals	N/A	Yes	2.3.1.2
Reactor Coolant	RC	Yes	2.3.1.3
Steam Generator	N/A	Yes	2.3.1.4
Engineered Safety Features			
Reactor Building Spray	SP	Yes	2.3.2.1
Refueling Water	RW	Yes	2.3.2.2
Residual Heat Removal	RH	Yes	2.3.2.3
Safety Injection	SI	Yes	2.3.2.4
Auxiliary Systems			
Air Handling and Local Ventilation and Cooling	AH, VL	Yes	2.3.3.1
Auxiliary Coolant	AC	Yes	2.3.3.2
Boron Recycle	BR	Yes	2.3.3.3
Building Services	BS	Yes	2.3.3.4
Chemical and Volume Control	CS, CV	Yes	2.3.3.5
Chilled Water	VU	Yes	2.3.3.6
Circulating Water	CW	Yes	2.3.3.7
Component Cooling	CC	Yes	2.3.3.8
Demineralized Water	DN	Yes	2.3.3.9
Diesel Generator Services	DG	Yes	2.3.3.10
Domestic Water	DO	Yes	2.3.3.11
Excess Liquid Waste	WX	Yes	2.3.3.12
Fire Service	FS	Yes	2.3.3.13
Fuel Handling	FH	Yes	2.3.3.14

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference[1]
Gaseous Waste Processing	WG	Yes	2.3.3.15
Hydrogen Removal, Post Accident	HR	Yes	2.3.3.16
Incore Instrumentation	IC	Yes	2.3.3.17
Industrial Cooler	CI	Yes	2.3.3.18
Instrument Air	IA	Yes	2.3.3.19
Leak Detection	LD	Yes	2.3.3.20
Liquid Effluents From Nuclear Plant to Penstock	LW	Yes	2.3.3.21
Liquid Waste Processing	WL	Yes	2.3.3.22
Material Handling	MH	Yes	2.3.3.23
Nitrogen Blanketing	NG	Yes	2.3.3.24
Nuclear and Miscellaneous Drains	ND, MD	Yes	2.3.3.25
Nuclear Sampling	SS	Yes	2.3.3.26
Radiation Monitoring	RM	Yes	2.3.3.27
Radwaste Solidification & Solids Handling	WD	Yes	2.3.3.28
Reactor Building Cooling Unit Drains	RD	Yes	2.3.3.29
Reactor Building Leak Rate Testing	LR	Yes	2.3.3.30
Reactor Makeup Water Supply	MU	Yes	2.3.3.31
Service Water	SW	Yes	2.3.3.32
Spent Fuel Cooling	SF	Yes	2.3.3.33
Station Service Air	SA	Yes	2.3.3.34
Thermal Regeneration	TR	Yes	2.3.3.35
Steam and Power Conversion Systems			
Auxiliary Boiler Steam and Feedwater	AS	Yes	2.3.4.1
Condensate	CO	Yes	2.3.4.2
Emergency Feedwater	EF	Yes	2.3.4.3

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference[1]
Extraction Steam	EX	Yes	2.3.4.4
Feedwater	FW	Yes	2.3.4.5
Gland Sealing Steam	GS	Yes	2.3.4.6
Main Steam	MS	Yes	2.3.4.7
Main Steam Dump	MB	Yes	2.3.4.8
Nuclear Blowdown Processing	NB	Yes	2.3.4.9
Steam Generator Blowdown	BD	Yes	2.3.4.10
Turbine Cycle Chemical Feed	WC	Yes	2.3.4.11
Turbine Cycle Sampling	WA	Yes	2.3.4.12
Turbine Electro-Hydraulic	EH	Yes	2.3.4.13
Administrative Equipment	AD	No	N/A
Calibrated Tools	CT	No	N/A
Carbon Dioxide	CD	No	FSAR 10.2.2.4
CO2 Purge - Nuclear	CN	No	FSAR 10.2.2.4
Condensate Demineralization	WI	No	FSAR 10.4.6
Condenser Air Removal	AR	No	FSAR 10.4.2
Condenser Cleaning	AT	No	FSAR 10.4.1.1
Cooling Tower Nuclear Training Center	CTN	No	N/A
Demineralized Water	DW	No	FSAR 9.2.3
Excitation system	XE	No	FSAR 10.2.2
Filtered Water	FI	No	FSAR 9.2.3.2
Flex Utility	FX	No	N/A
Fuel Oil Handling	FO	No	N/A
Generator and Main Transformer	EG	No	FSAR 1.2.3.6
Generator Stator Cooling	SC	No	N/A

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference[1]
Heater Drains	HD	No	FSAR 10.1
Heater Vents	HV	No	N/A
Helium Supply (no PAMS name)	HE	No	FSAR 9.1.5.1
Hydrogen	HY	No	FSAR 10.2.2.4
Inactive VCS (Emergency Power)	EP	No	N/A
Inactive VCS (Sewer)	SE	No	N/A
Inactive VCS (Sump Drains)	SD	No	N/A
Industrial Waste Processing	WP	No	FSAR 1.2.3.8.4
Lube Oil	LO	No	N/A
Main Turbine	TB	No	FSAR 10.2
Nitrogen – Nuclear Plant Use	NN	No	N/A
Nuclear Hydrogen	HN	No	FSAR 11.3
Nuclear Oxygen	ON	No	N/A
Raw Water Treatment	WT	No	FSAR 9.2.3.2
Reheat Steam	RS	No	FSAR 10.3.2
Respirator Fit Test	HP	No	N/A
Seal Oil	SO	No	N/A
Turbine Accessories	TA	No	N/A
Turbine Building Closed Cycle Cooling	TC	No	FSAR 10.4.10
Containments, Structures, and Component Supports			
Reactor Building (Containment)	RB	Yes	2.4.1.1
Auxiliary Building	AB	Yes	2.4.1.2
Auxiliary Service Building	AS, ASB	Yes	2.4.1.3
Circulating Water Intake Structure	CW	Yes	2.4.1.4
Component Supports	N/A	Yes	2.4.1.5

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference[1]
Control Building	CB	Yes	2.4.1.6
Diesel Generator Building	DB	Yes	2.4.1.7
Duct Banks	N/A	Yes	2.4.1.8
Earthen Embankments	N/A	Yes	2.4.1.9
Electrical Manholes	N/A	Yes	2.4.1.10
Electrical Substation and Transformer Areas	N/A	Yes	2.4.1.11
Fuel Handling Building	FB, FHB	Yes	2.4.1.12
Intermediate Building	IB	Yes	2.4.1.13
Miscellaneous Structural Commodities	N/A	Yes	2.4.1.14
NSSS Supports	N/A	Yes	2.4.1.15
Service Water Discharge Structure	N/A	Yes	2.4.1.16
Service Water Intake Structure	N/A	Yes	2.4.1.17
Service Water Pumphouse	SW, SWPH	Yes	2.4.1.18
Tank and Equipment Foundations	N/A	Yes	2.4.1.19
Turbine Building	TB	Yes	2.4.1.20
Water Treatment Building	WT, WTB	Yes	2.4.1.21
Auxiliary Boiler Fuel Oil Storage Tank and Berm	N/A	No	N/A
Auxiliary Boiler House	N/A	No	N/A
Auxiliary Fire Pump House	N/A	No	N/A
Circulating Water Discharge Canal	N/A	No	N/A
Circulating Water Discharge Structure	N/A	No	N/A
Closed Cycle Cooling Tower and Pumphouse	N/A	No	N/A
Containment Access Runway	N/A	No	N/A
Demineralized Water Pumphouse	N/A	No	N/A
Demineralized Water Tank Foundation	N/A	No	N/A

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference[1]
Filtered Water Storage Tank Foundation	N/A	No	N/A
Hot Machine Shop	N/A	No	N/A
Independent Spent Fuel Storage Installation (ISFSI)	N/A	No	N/A
Industrial Waste Facility (Biological Treatment Ponds)	N/A	No	N/A
Jetty (Monticello Reservoir)	N/A	No	N/A
Miscellaneous Nonsafety-Related Buildings and Structures	N/A	No	N/A
Monticello Reservoir Dams	N/A	No	N/A
Nuclear Operations Building	N/A	No	N/A
Potable Water Pumphouse	N/A	No	N/A
Radiological Maintenance Building	N/A	No	N/A
Screen Wash Pumphouse	N/A	No	N/A
Service Building	N/A	No	N/A
Sodium Hydroxide Storage Tank Foundation (North of Water Treatment Building)	N/A	No	N/A
Electrical and I&C Systems			
Balance of Plant I&C	BP	Yes	FSAR 7.1.2.7, Table 7.1-3, 8.3.1
Control Room Evacuation	CE	Yes	FSAR 7.4.1.3
Rod Control & Position System	CR	Yes	FSAR 7.7.1.2
Electrical DC Distribution	ED	Yes	FSAR 8.3.2
Miscellaneous AC Distribution	EM	Yes	FSAR 8.3.1
Electrical System	ES	Yes	FSAR 1.2.3.6, 8.3
Heat Tracing	ET	Yes	N/A

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference[1]
AC Vital Buses (120V Distribution)	EV	Yes	FSAR 7.6.1, 7.2.1.1, Figure 8.3.3, Figures 8.2-3 & 8.2-4
Warehouse Electrical Equipment	EW	Yes	N/A
Main Control Board	MC	Yes	N/A
Miscellaneous Instrumentation (Pressure Flow Monitor System only)	MI	Yes	FSAR 9.3.4.2.5.24
Nuclear Instrumentation	NI	Yes	FSAR 7.2.1.1, 7.7.1.3.1
Plant Surveillance	PS	Yes	N/A
Reactor Protection Control System	RP	Yes	FSAR 7.2.2.3, 7.7.1.1
Engineered Safety Features	SG	Yes	FSAR 7.3.1.1, 8.3.1.1
Substation (230KV and 115kV Parr ESF)	TS	Yes	FSAR 8.2.1
Technical Support Center	TX	Yes	FSAR 7.7.3
Process Instrumentation and Control	XI	Yes	FSAR 6.3.2.18, 7.2.1.1
Annunciators	AA	No	FSAR 13.5.2.4
Computer	CP	No	N/A
Grounding & Cathodic Protection	EC	No	FSAR 8.3.1.1.4(7)
Communications	EE	No	FSAR 1.2.3.8.12, 9.5.2
Generator & Main Transformer	EG	No	FSAR 8.3
Earthquake Instrumentation	EI	No	N/A
Electrical Power	EP	No	FSAR 8.3
Inhouse Electrical Maintenance	IE	No	N/A
Integrated Control	IN	No	N/A
Low Frequency Grounding	LF	No	N/A

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference[1]
Miscellaneous Instrumentation (Incore Neutron Flux Monitoring System)	MI	No	FSAR 4.2.1.1.2, 7.2
Miscellaneous Instrumentation (Incore Temperature Monitoring System)	MI	No	FSAR 7.5.5
Miscellaneous Instrumentation (Core Cooling Monitoring System)	MI	No	FSAR 7.5.5
Miscellaneous Instrumentation (Reactor Vessel Level Indication System: RVLIS)	MI	No	FSAR 7.5.5
Miscellaneous Instrumentation (Loose Parts Monitoring System: LPMS)	MI	No	FSAR 4.4.5.4
Off-Site Warning System	OW	No	N/A
Vibration Monitoring (RCP Vibration Monitor)	VM	No	FSAR 5.5.1.2
Welding Receptacles	WE	No	N/A
Excitation System	XE	No	N/A

1. Indicated Reference is the SLRA Section unless noted otherwise

2.3 SCOPING AND SCREENING RESULTS: MECHANICAL SYSTEMS

2.3.1 REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

2.3.1.1 Reactor Vessel

System Description

The reactor vessel, fabricated by Chicago Bridge and Iron, Inc., is cylindrical, with a welded hemispherical bottom head and a removable, bolted, and flanged hemispherical upper closure head sealed by two hollow metallic O-rings. The vessel contains the core, core support structures, control rods, and other parts directly associated with the core. Inlet and outlet nozzles are located symmetrically around the vessel. The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear incore instrumentation.

A replacement reactor vessel closure head was designed by Westinghouse and fabricated by Doosan Heavy Industrial for installation in refueling outage RF-23 in the spring of 2017. The replacement is a single piece forging eliminating the dome to flange weld. Head adapters are installed for control rod drive mechanisms and are of an alloy 690 material and weld, which is much less susceptible to cracking than the original alloy 600 components. The head adapters are tubular members welded to the head assembly. The assembly eliminates a lower canopy seal weld with a full penetration bimetal weld to the latch housing.

System Evaluation Boundary

The evaluation boundary for the reactor vessel components subject to aging management review includes the vessel shell, flange, welded attachments, nozzles, safe ends and flanges, control rod drive mechanism housings, head adapters, instrumentation tubes, the reactor vessel head, closure stud assemblies, lifting lugs, and seal table components. The closure head flange O-rings are periodically replaced, and therefore, not subject to aging management review.

System Intended Functions

The reactor vessel performs the following safety-related functions: The reactor vessel maintains the reactor coolant system pressure boundary and provides a fission product barrier, supports and contains the reactor core and core support structures, supports and contains the control rod drive mechanism internals, supports and guides reactor controls and instrumentation, and contains the reactor coolant around the reactor core and directs the coolant flow into the core and out into the reactor coolant piping and upper head. Therefore, the reactor vessel is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The reactor vessel is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Pressurized Thermal Shock (10 CFR 50.61), and Station Blackout

(10 CFR 50.63). Therefore, the reactor vessel is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the reactor vessel can be found in the FSAR, Sections 5.1, 5.2.1, and 5.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the reactor vessel are listed below:

SLR-302-601

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.1-1 Reactor Vessel.

The aging management review results for these component types are indicated in Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation.

2.3.1.2 Reactor Vessel Internals

System Description

The components of the reactor vessel internals are divided into three parts consisting of the lower core support structure (including the entire core barrel and neutron shield pad assembly), the upper core support structure and the incore instrumentation support structure.

The coolant flows from the vessel inlet nozzles down the annulus between the core barrel and the vessel wall and into a plenum at the bottom of the vessel. The coolant then reverses direction and flows up through the core support and lower core plates. After passing through the core, the coolant enters the region of the upper support structure and then flows radially to the core barrel outlet nozzles and directly through the vessel outlet nozzles.

System Evaluation Boundary

The evaluation boundary for the reactor vessel internals components that are subject to aging management review includes alignment and interfacing components, neutron shield pads, and subcomponents of the baffle and former assembly, bottom-mounted instrumentation, control rod guide tube assemblies, core barrel assembly, lower internals assembly, lower support assembly, and upper internals assembly. Fuel assemblies are periodically replaced, and control rods are active components; therefore, these components are not subject to aging management review.

System Intended Functions

The reactor vessel internals perform the following safety-related functions: The reactor vessel internals support the core, maintain fuel alignment, limit fuel assembly movement, and maintain alignment between fuel assemblies and control rod drive mechanisms; direct coolant flow past the fuel elements and to the pressure vessel closure head; provide gamma and neutron shielding for the reactor vessel; provide guides for the incore instrumentation; and provide a reactor coolant pressure boundary via the flux thimble tubes. Therefore, the reactor vessel internals are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

FSAR References

Additional details of the reactor vessel internals can be found in the FSAR, Section 4.2.2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the reactor vessel internals.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.1-2 Reactor Vessel Internals.

The aging management review results for these component types are indicated in Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation.

2.3.1.3 Reactor Coolant

System Description

The reactor coolant system consists of three similar heat transfer loops connected in parallel to the reactor pressure vessel. Each loop contains a reactor coolant pump, steam generator, and associated piping and valves. In addition, the system includes a pressurizer, pressurizer relief tank, interconnecting piping, and instrumentation necessary for operational control. These components are located in the Reactor Building.

During operation, the reactor coolant system transfers heat generated in the core to the steam generators, where steam is produced to drive the turbine-generator. Borated demineralized water is circulated in the reactor coolant system at a flowrate and temperature consistent with achieving the required reactor core thermal-hydraulic performance. The water also acts as a neutron moderator and reflector, and as a solvent for the neutron absorber (boron) used in chemical shim control.

The reactor coolant system pressure boundary provides a barrier against the release of radioactivity generated within the reactor and is designed to ensure a high degree of integrity throughout the life of the plant.

System Evaluation Boundary

The evaluation boundary for the reactor coolant system components subject to aging management review includes the piping and components from the reactor pressure vessel nozzle safe-ends to the steam generator inlet nozzle safe-ends, and from the steam generator outlet nozzle safe-ends through the reactor coolant pumps to the reactor vessel inlet nozzle safe-ends. The evaluation boundary also includes the pressurizer surge line, pressurizer spray lines, and pressurizer and pressurizer subcomponents. The pressurizer spray head does not form part of the reactor coolant pressure boundary and is not credited for mitigation of any of the accidents addressed in FSAR Chapter 15. The spray head does not provide structural support of reactor coolant pressure boundary components and does not have a (nonsafety-related) leakage boundary function, as it is not designed to retain water without leakage and is entirely contained within the pressurizer. The internal and external surfaces of the spray head are exposed to nearly the same pressure, and the potential for generation of loose parts due to cracking is a hypothetical system interaction that has not been reported in industry operating experience. The spray head is not credited for compliance with regulated events. Therefore, the pressurizer spray head is not within the scope of subsequent license renewal.

The reactor coolant system has nonsafety-related fluid-retaining components whose failure could result in spatial interactions with safety-related components and contains nonsafety-related components that provide structural support to safety-related components. The reactor vessel, reactor vessel internals, and steam generators are within the scope of subsequent license renewal but are evaluated separately in other subsequent license renewal application sections.

The evaluation boundary also includes the reactor coolant pump motor oil collection system components.

System Intended Functions

The reactor coolant system performs the following safety-related functions: The reactor coolant system provides a pressure boundary for the reactor coolant; removes core decay, latent, and reactor coolant pump heat, and controls core reactivity during normal operations, shutdown and following a design basis event; provides reliable isolation of each relief path via the pressurizer power operated relief valve (PORV) block valves if excessive leakage occurs; and provides a bleed path for “feed and bleed” via the pressurizer PORVs and block valves. The system also mitigates the consequences of design basis events and provides containment isolation. Therefore, the reactor coolant system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The reactor coolant system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the reactor coolant system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The reactor coolant system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout

(10 CFR 50.63). Therefore, the reactor coolant system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the reactor coolant system can be found in the FSAR, Sections 3.1.2 and 4.3.2.5; Chapters 5 and 15; Table 6.2-54.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the reactor coolant system are listed below:

SLR-302-601

SLR-302-602

SLR-302-606

SLR-302-612

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.1-3 Reactor Coolant.

The aging management review results for these component types are indicated in Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation.

2.3.1.4 Steam Generators

System Description

The steam generators installed at VCSNS are Westinghouse Delta-75, feedring type steam generators. The steam generators are vertical shell and U-tube evaporators with integral moisture separation equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. The feedwater enters at approximately two-thirds of the steam generator height and is distributed equally around the circumference of the steam generator shell. Feedwater enters the tube bundle by flowing downward between the steam generator external shell and inner wrapper barrel. An open area at the bottom of the wrapper barrel permits the feedwater to enter the tube bundle. Steam is generated and flows upward through the moisture separators and flow restrictor outlet nozzle at the top of the steam drum. High efficiency centrifugal steam separators remove most of the entrained water. Dryers are employed to increase the steam quality to a minimum of 99.90% (0.10% moisture).

System Evaluation Boundary

The evaluation boundary for the steam generator components subject to aging management review includes the subcomponents that provide pressure boundary integrity, structural support, flow distribution, and steam flow restriction.

System Intended Functions

The steam generators perform the following safety-related functions: The steam generators remove core decay, latent and reactor coolant pump heat during normal operations, shutdown, and following a design basis event; provide a pressure boundary for the reactor coolant during normal operations, shutdown, and following a design basis event; and limit the steam release rate during a main steam line break transient. Therefore, the steam generators are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The steam generators are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the steam generators are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the steam generators can be found in the FSAR, Sections 5.1, 5.2.1, 5.5.2, and 15.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the steam generators are listed below:

SLR-302-601

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.1-4 Steam Generators.

The aging management review results for these component types are indicated in Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation.

Screening Results Tables: Reactor Vessel, Internals, and Reactor Coolant System

Table 2.3.1-1 Reactor Vessel

Subcomponent	Intended Function(s)
Bottom head dome	Pressure Boundary
Bottom mounted instrumentation (guide tube)	Pressure Boundary
Bottom mounted instrumentation (nozzle and weld)	Pressure Boundary
Closure head (core exit thermocouple nozzle)	Pressure Boundary
Closure head (dome and flange)	Pressure Boundary
Closure head (instrument port head adaptor)	Pressure Boundary
Closure head (lifting lug)	Structural Support
Closure head (stud, nut, and washer)	Pressure Boundary
Closure head (vent and level instrumentation nozzle)	Pressure Boundary
Control rod drive mechanism (extension tube)	Pressure Boundary
Control rod drive mechanism (guide funnel)	Pressure Boundary
Control rod drive mechanism (head adapter and weld)	Pressure Boundary
Control rod drive mechanism (latch housing)	Pressure Boundary
Control rod drive mechanism (nozzle, j-groove weld)	Pressure Boundary
Control rod drive mechanism (rod travel housing)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-1 Reactor Vessel

Subcomponent	Intended Function(s)
Core support pad	Structural Support
Primary nozzle and support pad	Pressure Boundary, Structural Support
Primary nozzle safe end	Pressure Boundary
Primary nozzle weld	Pressure Boundary
Refueling seal ledge	Structural Support
Seal table	Structural Support
Seal table (fitting)	Pressure Boundary
Ventilation shroud support ring	Structural Support
Vessel flange and core support ledge	Pressure Boundary
Vessel flange leakage monitor tube	Pressure Boundary
Vessel shell (upper, intermediate, lower)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.1.2-1, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-2 Reactor Vessel Internals

Subcomponent	Intended Function(s)
Alignment and interfacing components (clevis bearing wear surface)	Structural Support
Alignment and interfacing components (clevis insert bolt)	Structural Support
Alignment and interfacing components (internals hold-down spring)	Structural Support
Alignment and interfacing components (upper core plate alignment pin)	Structural Support
Alignment and interfacing components (upper core plate insert)	Structural Support
Baffle and former assembly (baffle edge bolt, bolting lock device)	Structural Support
Baffle and former assembly (baffle plate)	Flow Distribution, Structural Support
Baffle and former assembly (baffle-former bolt)	Structural Support
Baffle and former assembly (barrel-former bolt)	Structural Support
Baffle and former assembly (former plate)	Structural Support
Bottom mounted instrumentation (column body)	Structural Support
Bottom mounted instrumentation (column cruciform)	Structural Support
Control rod guide tube assembly and flow downcomer (C-tube and sheath)	Structural Support
Control rod guide tube assembly and flow downcomer (guide plate (card))	Structural Support

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-2 Reactor Vessel Internals

Subcomponent	Intended Function(s)
Control rod guide tube assembly and flow downcomer (lower flange weld)	Structural Support
Control rod guide tube assembly and flow downcomer (remaining lower flange weld)	Structural Support
Core barrel assembly (core barrel flange)	Flow Distribution, Structural Support
Core barrel assembly (lower flange weld)	Structural Support
Core barrel assembly (lower girth weld)	Structural Support
Core barrel assembly (middle & lower axial weld)	Structural Support
Core barrel assembly (upper axial weld)	Structural Support
Core barrel assembly (upper flange weld)	Structural Support
Core barrel assembly (upper girth weld)	Structural Support
Flux thimble (tube)	Pressure Boundary, Structural Support
Lower internals (lower core plate)	Flow Distribution, Structural Support
Lower internals (lower support forging)	Structural Support
Lower internals (radial key wear surface)	Structural Support
Lower support column assembly (column body)	Structural Support
Lower support column assembly (column bolt)	Structural Support

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-2 Reactor Vessel Internals

Subcomponent	Intended Function(s)
No additional measures components	Enclosure Protection, Spray Pattern, Structural Support
Reactor vessel internal components	Enclosure Protection, Flow Distribution, Structural Support
Upper internals (upper core plate)	Structural Support
Upper support plate assembly (upper support ring or skirt0	Structural Support

The aging management review results for these component types are indicated in Table 3.1.2-2, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-3 Reactor Coolant

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Drip pan (RCP oil collection)	Leakage Boundary (Spatial)
Flame arrestor	Fire Barrier
Flexible hose	Pressure Boundary
Heat exchanger (RCP motor lower bearing cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (RCP motor oil cooler - channel)	Pressure Boundary
Heat exchanger (RCP motor oil cooler - shell)	Pressure Boundary
Heat exchanger (RCP motor oil cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (RCP motor oil cooler - tubesheet)	Pressure Boundary
Heat exchanger (thermal barrier - tube)	Heat Transfer, Pressure Boundary
Hydraulic isolator	Pressure Boundary
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping (reactor vessel flange leakage detection line)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components (Class 1 <NPS 4)	Pressure Boundary
Piping, piping components (Class 1)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-3 Reactor Coolant

Component Type	Intended Function(s)
Pressurizer (heater well coupling)	Pressure Boundary
Pressurizer (instrument and sample tube and coupling)	Pressure Boundary
Pressurizer (lower and upper heads)	Pressure Boundary
Pressurizer (manway cover bolting)	Pressure Boundary
Pressurizer (manway cover)	Pressure Boundary
Pressurizer (nozzle and manway forgings)	Pressure Boundary
Pressurizer (nozzle safe end)	Pressure Boundary
Pressurizer (nozzle weld overlay)	Pressure Boundary
Pressurizer (nozzle weld)	Pressure Boundary
Pressurizer (seismic lug)	Structural Support
Pressurizer (shell)	Pressure Boundary
Pressurizer (spray and surge nozzle thermal sleeves)	Limit Thermal Cycling
Pressurizer (support skirt)	Structural Support
Pump casing (reactor coolant)	Pressure Boundary
Rupture disc	Leakage Boundary (Spatial)
Tank (pressurizer relief)	Leakage Boundary (Spatial)
Tank (RCP oil collection enclosure)	Leakage Boundary (Spatial)
Tank (RCP oil collection)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-3 Reactor Coolant

Component Type	Intended Function(s)
Valve body (Class 1)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.1.2-3, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-4 Steam Generators

Subcomponent	Intended Function(s)
Anti-vibration bar	Structural Support
Anti-vibration bar retaining ring and bar	Structural Support
Auxiliary feedwater internal spray pipe	Pressure Boundary, Spray Pattern
Auxiliary feedwater nozzle	Pressure Boundary
Auxiliary feedwater nozzle thermal sleeve	Limit Thermal Cycling
Blowdown header	Flow Distribution
Channel head	Pressure Boundary
Channel head divider plate	Flow Distribution
Channel head drain tube	Pressure Boundary
Feedwater distribution ring	Flow Distribution
Feedwater distribution ring safe end	Flow Distribution
Feedwater distribution ring spray nozzle	Spray Pattern
Feedwater nozzle	Pressure Boundary
Feedwater nozzle thermal sleeve	Limit Thermal Cycling
Moisture separator assembly	Flow Distribution
Moisture separator column assembly	Flow Distribution
Primary inlet and outlet nozzle	Pressure Boundary
Primary inlet and outlet nozzle safe end	Pressure Boundary
Primary inlet and outlet nozzle weld	Pressure Boundary
Primary manway	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-4 Steam Generators

Subcomponent	Intended Function(s)
Primary manway cover	Pressure Boundary
Primary manway cover bolting	Pressure Boundary
Primary manway cover insert	Pressure Boundary
Secondary manway	Pressure Boundary
Secondary manway cover	Pressure Boundary
Secondary manway cover bolting	Pressure Boundary
Secondary side shell (lower shell, upper shell, transition cone, closure weld)	Pressure Boundary
Secondary side shell (penetration cover bolting)	Pressure Boundary
Secondary side shell (penetration cover)	Pressure Boundary
Secondary side shell (penetration)	Pressure Boundary
Secondary side shell (upper head and steam outlet nozzle)	Pressure Boundary
Steam flow limiter	Restricts Flow
Support pad	Structural Support
Tube	Heat Transfer, Pressure Boundary
Tube bundle stay rod and spacer	Structural Support
Tube bundle support and baffle plate	Flow Distribution, Structural Support
Tube bundle wrapper	Flow Distribution, Structural Support
Tube plug	Pressure Boundary
Tubesheet	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-4 Steam Generators

Subcomponent	Intended Function(s)
Tube-to-tubesheet weld	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.1.2-4, Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

2.3.2 ENGINEERED SAFETY FEATURES

2.3.2.1 Reactor Building Spray

System Description

The reactor building spray system removes the thermal energy released to containment by a loss-of-coolant accident (LOCA) at a rate sufficient to limit the resulting over-pressurization to a level below the design limit, thereby maintaining Reactor Building structural integrity. The system then reduces the over-pressure to minimize the pressure differential which induces leakage out of containment. The reactor building spray system also reduces the concentration of airborne radioactive iodine in the containment atmosphere.

These functions are accomplished by spraying water containing sodium hydroxide (NaOH) into the Reactor Building atmosphere to absorb heat, condense steam and remove airborne radioactive iodine from the steam-air atmosphere.

The system consists of two independent and redundant subsystems, each consisting of a pump, two reactor building sump isolation valves, one refueling water storage tank (RWST) isolation valve, one sodium hydroxide storage tank isolation valve, one discharge isolation valve, three ring headers, 165 spray nozzles, and connecting piping, manual maintenance valves, and check valves. The two subsystems share the sodium hydroxide storage tank and the full flow test line to the RWST.

During normal plant operation, the reactor building spray system is in a standby condition. Operation of the system is automatically initiated following a LOCA or main steam line break by signals from the engineered safety features actuation system, when the Reactor Building pressure increases to the actuation set point.

System Evaluation Boundary

The evaluation boundary for the reactor building spray system components subject to aging management review includes the sodium hydroxide storage tank, suction lines from the RWST and sodium hydroxide storage tank, and from the containment sump strainers through the spray pumps to the containment spray rings, and test lines back to the RWST; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components. Thermal insulation on safety-related outdoor piping and instrumentation associated with the sodium hydroxide storage tank is also subject to aging management review.

Containment sump strainers are evaluated with the safety injection system. The guard pipes, expansion joints, and isolation valve chambers for containment sump suction are addressed in the structural section of the application.

System Intended Functions

The reactor building spray system performs the following safety-related functions: The system provides borated water and NaOH solution spray and recirculation during accident conditions and provides containment isolation. Therefore, the reactor building spray system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The reactor building spray system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the reactor building spray system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The reactor building spray system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Environmental Qualification (10 CFR 50.49). Therefore, the reactor building spray system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the reactor building spray system can be found in the FSAR, Section 6.2.2.2.1 and Table 6.2-53.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the reactor building spray system are listed below:

SLR-302-661

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.2-1, Reactor Building Spray.

The aging management review results for these component types are indicated in Table 3.2.2-1, Engineering Safety Features - Reactor Building Spray - Aging Management Evaluation.

2.3.2.2 Refueling Water

System Description

The refueling water system supports refueling operations, refueling water cleanup, spent fuel pool makeup, and other borated water needs associated with normal plant operations. The refueling water system also operates in conjunction with the chemical and volume control, residual heat removal and safety injection systems to deliver borated emergency core cooling water to the reactor coolant system following a loss-of-coolant accident. During the injection phase, the refueling water storage tank provides an adequate supply of borated water for the residual heat removal and centrifugal charging pumps for injection directly into the reactor coolant system.

System Evaluation Boundary

The evaluation boundary for the refueling water system components subject to aging management review consists of the refueling water storage tank and its internal anti-vortex baffle. Thermal insulation on the refueling water storage tank is also subject to aging management review.

The foundation for the refueling water storage tank is addressed in the structural section of this application.

System Intended Functions

The refueling water system performs the following safety-related functions: The system provides a source of borated water to the spent fuel cooling system, the residual heat removal system, the reactor building spray system, and the safety injection system for normal and post-accident use. Therefore, the refueling water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The refueling water system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the refueling water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the refueling water system can be found in the FSAR, Sections 6.3.2.4, 6.3.2.6 and 9.1.3, and Table 9.1-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the refueling water system are listed below:

SLR-302-651

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.2-2, Refueling Water.

The aging management review results for these component types are indicated in Table 3.2.2-2, Engineering Safety Features - Refueling Water - Aging Management Evaluation.

2.3.2.3 Residual Heat Removal

System Description

The primary function of the residual heat removal system is to remove radioactive decay heat energy from the core, and sensible and pump heat from the reactor coolant system during plant cooldown and refueling operations. The residual heat removal system also operates in conjunction with the chemical and volume control, refueling water and safety injection systems to deliver borated emergency core cooling water to the reactor coolant system following a loss-of-coolant accident (LOCA). The system operation is categorized in two phases: injection and recirculation.

During the injection phase, the residual heat removal pumps, along with the centrifugal charging pumps in the chemical and volume control system, draw suction from the refueling water storage tank and inject borated water directly into the reactor coolant system. During the recirculation phase, the residual heat removal pumps draw suction from the containment sump, remove decay heat via the residual heat removal system heat exchangers, and then deliver flow to the charging pumps suction and to the reactor coolant system. As during the injection phase, the charging pumps then inject borated water directly into the reactor coolant system.

System Evaluation Boundary

The evaluation boundary for the residual heat removal system components subject to aging management review includes the flowpath from the reactor coolant system, through the residual heat removal pumps and heat exchangers to safety injection piping that returns the residual heat removal flow to the reactor coolant system, the branch lines to other systems, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The residual heat removal system performs the following safety related functions: The system removes heat from the reactor coolant system, provides low-head injection and supports low/high head recirculation during accident conditions, provides a reactor coolant pressure boundary, and provides containment isolation. Therefore, the residual heat removal system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The residual heat removal system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the residual heat removal system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The residual heat removal system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Environmental Qualification (10 CFR 50.49). Therefore, the residual heat removal system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the residual heat removal system can be found in the FSAR, Sections 3.1.2.4, 5.5.7, 6.3.2.2.4.1, and Table 6.2-53.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the residual heat removal system are listed below:

SLR-302-641

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.2-3, Residual Heat Removal.

The aging management review results for these component types are indicated in Table 3.2.2-3, Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation.

2.3.2.4 Safety Injection

System Description

The safety injection system operates in conjunction with the chemical and volume control, refueling water and residual heat removal systems to deliver borated emergency core cooling water to the reactor coolant system following a loss-of-coolant accident (LOCA). The principal components of the safety injection system that provide emergency core cooling immediately following a LOCA are the accumulators (one for each loop), three chemical and volume control system charging pumps and two residual heat removal system pumps. The system operation is categorized in two phases: injection and recirculation.

During the injection phase, the residual heat removal pumps, along with the centrifugal charging pumps draw suction from the refueling water storage tank and inject borated water directly into the reactor coolant system. In addition, the gas pressurized accumulators discharge borated water directly into the reactor coolant system. During the recirculation phase, the residual heat removal pumps draw suction from the containment sump, remove decay heat via the residual heat removal system heat exchangers, and then deliver flow to the charging pumps suction and the reactor coolant system. As during the injection phase, the charging pumps then inject borated water directly into the reactor coolant system.

System Evaluation Boundary

The evaluation boundary for the safety injection system components that are subject to aging management review includes the safety-related flowpaths from the refueling water storage tank and from the containment sump strainers to the residual heat removal pumps and from those pump discharges to the reactor coolant system; the suction flowpaths to the charging pump suctions from the refueling water storage tank and from the residual heat removal pumps; the flowpaths from the charging pump discharges to the reactor coolant system; and the accumulators, the accumulator fill, drain and test lines, and discharge flowpaths to the reactor coolant system. The containment sump strainers serve both the safety injection and the reactor building spray systems but are evaluated with the safety injection system. Additionally, nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components are subject to aging management review. Some nonsafety-related valves within the safety injection check valve testing flowpaths that have residual heat removal system designations are evaluated with the safety injection system.

The high-head safety injection pumps provide a dual function as charging pumps and are evaluated for the effects of aging with the chemical and volume control system components. The residual heat removal pumps provide a dual function as shutdown heat removal pumps and are evaluated for the effects of aging with the residual heat removal system. The guard pipes, expansion joints, and isolation valve chambers for containment sump suction are addressed in the structural section of the application.

System Intended Functions

The safety injection system performs the following safety-related functions: The system provides borated emergency cooling water to the reactor coolant system during the injection and recirculation phases during emergency conditions, provides containment isolation, and provides a reactor coolant pressure boundary. Therefore, the safety injection system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The safety injection system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the safety injection system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The safety injection system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Environmental Qualification (10 CFR 50.49). Therefore, the safety injection system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the safety injection system can be found in the FSAR, Section 6.3.2 and Table 6.2-53.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the safety injection system are listed below:

SLR-302-322

SLR-302-691

SLR-302-692

SLR-302-693

SLR-302-812

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.2-4, Safety Injection.

The aging management review results for these component types are indicated in Table 3.2.2-4, Engineering Safety Features - Safety Injection - Aging Management Evaluation.

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Screening Results Tables: Engineered Safety Features Systems

Table 2.3.2-1 Reactor Building Spray

Component Type	Intended Function(s)
Bolting	Pressure Boundary, Structural Integrity (Attached)
Flow element	Pressure Boundary, Restricts Flow
Insulation (safety-related heat traced components)	Thermal insulation
Orifice	Pressure Boundary, Restricts Flow, Structural Integrity (Attached)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (reactor building spray)	Pressure Boundary
Pump casing (sodium hydroxide recirculation)	Structural Integrity (Attached)
Sight glass	Structural Integrity (Attached)
Sight glass (body)	Structural Integrity (Attached)
Spray nozzle	Spray Pattern
Strainer body (element removed)	Pressure Boundary
Tank (sodium hydroxide storage)	Pressure Boundary
Valve body	Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.2.2-1 Engineering Safety Features - Reactor Building Spray - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.2-2 Refueling Water

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Insulation (refueling water storage tank)	Thermal insulation
Tank (refueling water storage tank - anti-vortex baffle)	Flow Distribution
Tank (refueling water storage tank)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.2.2-2 Engineering Safety Features - Refueling Water - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.2-3 Residual Heat Removal

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Flow element	Pressure Boundary, Restricts Flow
Heat exchanger (pump seal cooler - cover)	Pressure Boundary
Heat exchanger (pump seal cooler - shell)	Pressure Boundary
Heat exchanger (pump seal cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (residual heat - channel)	Pressure Boundary
Heat exchanger (residual heat - shell)	Pressure Boundary
Heat exchanger (residual heat - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (residual heat - tubesheet)	Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Piping, piping components (Class 1)	Pressure Boundary
Pump casing (residual heat removal)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary
Valve body (Class 1)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.2.2-3 Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.2-4 Safety Injection

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Containment sump strainer (frame, element and duct)	Filtration
Flow element	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components (Class 1 <NPS 4)	Pressure Boundary
Piping, piping components (Class 1)	Pressure Boundary
Pump casing (hydro-test)	Leakage Boundary (Spatial)
Tank (accumulator)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Valve body (Class 1)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

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2.3.3 AUXILIARY SYSTEMS

2.3.3.1 Air Handling and Local Ventilation and Cooling

System Description

The air handling system and the local ventilation and cooling systems were evaluated together because both systems contain similar components and appear on the many of the same drawings. The combined system is comprised of multiple ventilation subsystems that provide space and equipment ventilation and cooling. Certain subsystems also provide radiological controls.

System Evaluation Boundary

The evaluation boundary for the air handling and local ventilation and cooling systems components subject to aging management review includes safety-related containment penetration components, air handling units and associated dampers and duct components, and backup air accumulators and piping components for operation of control room isolation dampers; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components. Also subject to aging management review are nonsafety-related fire damper assemblies and duct that prevent the spread of fire.

System Intended Functions

The air handling and local ventilation and cooling systems perform the following safety-related functions: The systems provide containment isolation, include safety-related ductwork to mitigate potential high energy line breaks, ventilate various plant areas for equipment cooling and personnel occupation, and route potentially contaminated air through charcoal filters prior to discharge to the environment. Therefore, the air handling and local ventilation and cooling systems are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The air handling and local ventilation and cooling systems contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the air handling and local ventilation and cooling systems are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The air handling and local ventilation and cooling systems are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Environmental Qualification (10 CFR 50.49). Therefore, the air handling and local ventilation and cooling systems are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the air handling and local ventilation and cooling system can be found in the FSAR, Section 9.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the air handling and local ventilation and cooling system are listed below:

SLR-302-852

SLR-912-102

SLR-912-103

SLR-912-105

SLR-912-120

SLR-912-125

SLR-912-130

SLR-912-131

SLR-912-132

SLR-912-134

SLR-912-136

SLR-912-138

SLR-912-139

SLR-912-140

SLR-912-141

SLR-912-142

SLR-912-144

SLR-912-147

SLR-912-150

SLR-912-154

SLR-912-155

SLR-912-157

SLR-912-158

SLR-912-170

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-1, Air Handling and Local Ventilation and Cooling.

The aging management review results for these component types are indicated in Table 3.3.2-1, Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation.

2.3.3.2 Auxiliary Coolant

System Description

The original design for the auxiliary coolant system (called CRDM cooling water system in the FSAR) was to provide cooling water to the control rod drive mechanism ventilation as a means of making up the difference between the required and actual cooling capacity of the reactor building cooling units. With the successful completion of the Reactor Building cooling upgrade modification, the cooling capacity provided by the auxiliary coolant system is no longer required. The equipment in the auxiliary coolant system is no longer required, and is pending future demolition.

System Evaluation Boundary

The evaluation boundary for the auxiliary coolant system components subject to aging management review includes the nonsafety-related components that retain water in buildings containing safety-related components.

System Intended Functions

The auxiliary coolant system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the auxiliary coolant system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

FSAR References

Additional details of the auxiliary coolant system can be found in the FSAR, Section 9.4.7.2.10.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the auxiliary coolant system are listed below:

SLR-302-852

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-2, Auxiliary Coolant.

The aging management review results for these component types are indicated in Table 3.3.2-2, Auxiliary Systems - Auxiliary Coolant - Aging Management Evaluation.

2.3.3.3 Boron Recycle

System Description

The boron recycle system collects and recycles reactor coolant effluent for reuse of the boric acid and makeup water. The system decontaminates the effluent by means of demineralization and gas stripping, and uses evaporation to separate and recover the boric acid and makeup water.

System Evaluation Boundary

The evaluation boundary for the boron recycle system components subject to aging management review includes heat exchangers and a valve that provide safety-related boundaries for the component cooling water and chemical and volume control systems; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or steam in buildings containing safety-related components.

The safety-related heat exchangers in the system provide integrity for the component cooling water system but cooling of the boron recycle flowpaths is not an intended function, so the heat exchangers do not perform a heat transfer function.

System Intended Functions

The boron recycle system performs the following safety-related function: The system provides a safety-related pressure boundary for the chemical and volume control and component cooling water systems. Therefore, the boron recycle system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The boron recycle system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the boron recycle system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

FSAR References

Additional details of the boron recycle system can be found in the FSAR, Section 9.3.6.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the boron recycle system are listed below:

SLR-09-269

SLR-302-751

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-3, Boron Recycle.

The aging management review results for these component types are indicated in Table 3.3.2-3, Auxiliary Systems - Boron Recycle - Aging Management Evaluation.

2.3.3.4 Building Services

System Description

The building services system contains structural and administrative components associated with various structures on site. Additionally, the building services system contains valves and piping components that maintain the pressure boundary for the Reactor Building personnel and emergency airlocks.

System Evaluation Boundary

The evaluation boundary for the building services system components subject to aging management review includes the safety-related equalizing and air supply valves and piping components that provide containment integrity at the personnel airlock and emergency airlock.

The personnel airlock and emergency airlock are addressed in the structural section of the application.

System Intended Functions

The building services system performs the following safety-related functions: The system provides containment isolation. Therefore, the building services system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

FSAR References

Additional details of the building services system can be found in the FSAR, Section 3.8.1.1.2.3 and Figures 3.8-19 through 3.8-20a.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the building services system.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-4, Building Services.

The aging management review results for these component types are indicated in Table 3.3.2-4, Auxiliary Systems - Building Services - Aging Management Evaluation.

2.3.3.5 Chemical and Volume Control

System Description

The chemical and volume control system provides reactor coolant system letdown and make-up for chemistry control, purification of reactor coolant system fluid, and control of chemical shim concentration for reactivity control. The system also provides reactor coolant pump seal injection flow, processing of reactor coolant pump seal leak-off flow, and reactor coolant system pressurizer level/inventory control. The chemical and volume control system charging pumps provide a dual function as the high-head safety injection pumps during emergency conditions. The system also includes chemical addition, boric acid batching, and borated water storage capability.

Portions of system are within the ASME Class 1 reactor coolant system pressure boundary. Additionally, most chemical and volume control vents and drains system components are evaluated with the chemical and volume control system and provide vent and drain paths for the system.

System Evaluation Boundary

The evaluation boundary for the chemical and volume control system components subject to aging management review includes the letdown flowpath from the reactor coolant system through the regenerative and letdown heat exchangers and letdown demineralizers to the volume control tank, the flowpaths from the volume control tank or refueling water storage tank through the charging pumps to the reactor coolant system; the boric acid tanks, pumps and flowpaths to the charging pump suction flowpath; the reactor coolant pump seal injection flowpath and leakoff flowpath through the seal water heat exchanger; the flowpath through the excess letdown heat exchanger; the lubricating oil flowpaths through the charging pump oil coolers and oil pumps; and nonsafety-related components that retain water or steam in buildings containing safety-related components. Thermal insulation within containment penetrations is also subject to aging management review.

Chemical and volume control vents and drains system valves that appear on thermal regeneration system drawings are evaluated with the thermal regeneration system.

System Intended Functions

The chemical and volume control system performs the following safety-related functions: The system provides a flow path and the motive force for safety injection; provides reactor coolant pump seal injection flow; provides containment isolation; and controls reactor coolant system inventory, pressure, and core reactivity. Therefore, the chemical and volume control system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The chemical and volume control system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the chemical and volume control system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The chemical and volume control system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the chemical and volume control system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the chemical and volume control system can be found in the FSAR, Sections 6.3 and 9.3.4, and Table 6.2-53.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the chemical and volume control system are listed below:

SLR-12-004

SLR-302-322

SLR-302-671

SLR-302-672

SLR-302-673

SLR-302-674

SLR-302-675

SLR-302-677

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-5, Chemical and Volume Control.

The aging management review results for these component types are indicated in Table 3.3.2-5, Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation.

2.3.3.6 Chilled Water

System Description

The chilled water system provides a continuous flow of chilled water through various ventilation chilled water coils in different areas of the plant. The chilled water system is a closed system with redundant supply and return mains. The HVAC mechanical water chillers reject the total heat load from the refrigeration system to the service water system.

System Evaluation Boundary

The evaluation boundary for the chilled water system components subject to aging management review includes safety-related chiller assemblies (composed of compressors, condensers, evaporators, and other support equipment), pumps, tanks, piping, and components which provide chilled water to ventilation cooling coils in various areas of the plant. The nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or oil in buildings containing safety-related components are also subject to aging management review.

System Intended Functions

The chilled water system performs the following safety-related function: The system maintains a continuous flow of chilled water to ventilation chilled water coils in the Control, Auxiliary, and Intermediate Buildings during normal and emergency conditions. Therefore, the chilled water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The chilled water system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the chilled water system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

FSAR References

Additional details of the chilled water system can be found in the FSAR, Section 9.4.7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the chilled water system are listed below:

SLR-302-841

SLR-302-842

SLR-302-843

SLR-302-845

SLR-54-064-2

SLR-54-660

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-6, Chilled Water.

The aging management review results for these component types are indicated in Table 3.3.2-6, Auxiliary Systems - Chilled Water - Aging Management Evaluation.

2.3.3.7 Circulating Water

System Description

The circulating water system removes thermal energy from the main and auxiliary condensers and dissipates this energy to the Monticello Reservoir. This system is not required to function under plant emergency or faulted conditions.

The circulating water system pumps trip on high level in the Turbine Building basement, as sensed by miscellaneous drains system instrumentation, to protect the Intermediate and Control Buildings from flooding. The system also contains traveling screens which are credited for filtration of fire pump supply water to support fire pump operability.

System Evaluation Boundary

The evaluation boundary for the circulating water system components subject to aging management review includes the nonsafety-related circulating water traveling screens and the circulating water pump pit isolation valves. There are no passive mechanical components required for the circulating water system to perform its flood mitigation function.

System Intended Functions

The circulating water system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the circulating water system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for flood mitigation.

The circulating water system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the circulating water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the circulating water system can be found in the FSAR, Section 10.4.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the circulating water system are listed below:

SLR-302-201

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-7, Circulating Water.

The aging management review results for these component types are indicated in Table 3.3.2-7, Auxiliary Systems - Circulating Water - Aging Management Evaluation.

2.3.3.8 Component Cooling

System Description

The component cooling system serves as an intermediate, closed-loop cooling system to transfer heat from systems and components important to safety, including those which may contain radioactive (or potentially radioactive) fluids, to the service water system. The component cooling system is also utilized during normal plant operation to transfer heat from various systems and components that are not important to safety but could result in the release of radioactivity to the ultimate heat sink if direct, open loop cooling were used. This latter type of service is referred to as "nonessential."

System Evaluation Boundary

The evaluation boundary for the component cooling system components subject to aging management review includes safety-related pumps, tanks, heat exchangers, piping and components which provide cooling water to the heat loads served by the system, as well as the backup instrument air supply to the service water crosstie valves. The nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components are also subject to aging management review.

System Intended Functions

The component cooling system performs the following safety-related functions: The system provides component cooling flow to essential equipment required to mitigate an accident, maintains component cooling flow for normal plant operation loads, and provides containment isolation. Therefore, the component cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The component cooling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the component cooling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The component cooling system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the component cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the component cooling system can be found in the FSAR, Section 9.2.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the component cooling system are listed below:

SLR-09-238

SLR-09-269

SLR-12-004

SLR-302-611

SLR-302-612

SLR-302-613

SLR-302-614

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-8, Component Cooling.

The aging management review results for these component types are indicated in Table 3.3.2-8, Auxiliary Systems - Component Cooling - Aging Management Evaluation.

2.3.3.9 Demineralized Water - Nuclear Services

System Description

The demineralized water - nuclear services system is a subset of the demineralized water system. The demineralized water system is designed to clarify, filter and demineralize raw water from Monticello Reservoir for distribution throughout the plant. The nuclear services portion of the system provides demineralized water to various nuclear oriented supporting systems. The only safety related equipment within the demineralized water - nuclear services system are containment isolation piping and valves.

System Evaluation Boundary

The evaluation boundary for the demineralized water - nuclear services system components subject to aging management review includes safety-related containment penetration piping and components, as well as nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The demineralized water - nuclear services system performs the following safety-related functions: The system provides containment isolation. Therefore, the demineralized water - nuclear services system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The demineralized water - nuclear services system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the demineralized water - nuclear services system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

FSAR References

Additional details of the demineralized water - nuclear services system can be found in the FSAR, Section 9.2.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the demineralized water - nuclear services system are listed below:

SLR-302-715

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-9, Demineralized Water - Nuclear Services.

The aging management review results for these component types are indicated in Table 3.3.2-9, Auxiliary Systems - Demineralized Water - Nuclear Services - Aging Management Evaluation.

2.3.3.10 Diesel Generator Services

System Description

The diesel generator services system contains two diesel generators that provide the emergency on-site power supply in the event of an off-site power interruption. Each diesel generator can supply 100 percent of the Engineered Safety Features loads plus other vital, non-nuclear, safety-related loads. Other than testing or maintenance, the emergency diesel generators operate only when auto started by a safety injection signal or a low voltage signal from their associated buses, and provide sufficient power to maintain the reactor in a safe condition.

The mechanical support subsystems of the diesel generators include: lubricating oil, fuel oil, cooling water, air intake & exhaust, air starting, and crankcase vacuum.

System Evaluation Boundary

The evaluation boundary for the emergency diesel generator system components that are subject to aging management review includes the safety-related fuel oil components from the underground fuel oil storage tanks, through underground piping, the fuel oil pumps, fuel oil tanks and associated piping to the diesel fuel injector headers; the starting air subsystem components from the start air tank supply isolation valves through the air receivers to the engine; the lubricating oil pumps, heat exchangers and piping components that are not integral to the engine; the cooling water expansion tanks, pumps, heat exchangers (excluding the turbocharger aftercoolers and governor coolers) and associated piping components; the exhaust piping from the turbocharger exhaust outlet through the mufflers to its discharge; as well as nonsafety-related components that provide leakage boundary or structural integrity. The engine, its integral components and the electrical generator are active components and are not subject to aging management review. The fuel injector headers, injectors, and accumulator tank; start air control valve, air start distributor and associated air start distribution to the cylinders; lubricating oil pan (sump); intake and exhaust manifolds; and turbochargers and blowers are integral to the active engine assembly and are not subject to aging management review. The starting air compressors are nonsafety-related and are not within-scope because the starting air tanks contain compressed air required to start the engines.

System Intended Functions

The diesel generator services system performs the following safety-related functions: The system provides emergency power to the class 1E onsite electrical buses during a loss of offsite power. Therefore, the diesel generator services system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The diesel generator services system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the diesel generator services system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for pressure boundary integrity, spatial interaction and structural integrity.

The diesel generator services system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the diesel generator services system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the diesel generator services system can be found in the FSAR, Sections 8.3.1.1.2 and 9.5.4 through 9.5.8.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the diesel generator services system are listed below:

SLR-302-281

SLR-302-351

SLR-302-353

SLR-32-005 Sh. 2

SLR-32-005 Sh. 3

SLR-32-005 Sh. 4

SLR-32-005 Sh. 5

SLR-32-005 Sh. 6

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-10, Diesel Generator Services.

The aging management review results for these component types are indicated in Table 3.3.2-10, Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation.

2.3.3.11 Domestic Water

System Description

The domestic water system provides potable water to lavatories, laundry facilities, drinking fountains, and eyewash/shower stations. The FSAR refers to the system as the potable water source.

System Evaluation Boundary

The evaluation boundary for the domestic water system components subject to aging management review includes nonsafety-related components that retain water in buildings containing safety-related components. Domestic water components in the Auxiliary Building, Fuel Handling Building, and Intermediate Building that retain water are subject to aging management review but are not shown on license renewal drawings.

System Intended Functions

The domestic water system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the domestic water system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

FSAR References

Additional details of the domestic water system can be found in the FSAR, Sections 9.2.3.2 and 9.2.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the domestic water system are listed below:

SLR-911-110

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-11, Domestic Water.

The aging management review results for these component types are indicated in Table 3.3.2-11, Auxiliary Systems - Domestic Water - Aging Management Evaluation.

2.3.3.12 Excess Liquid Waste

System Description

The excess liquid waste system works in concert with the liquid effluents from nuclear plant to penstock system and the liquid waste processing systems. Together, these systems are described as the liquid waste processing system in the FSAR.

The excess waste holdup tank is used to accept excess liquid waste from the liquid waste processing system floor drain tank, laundry and hot shower tank, and waste holdup tank when these tanks are filled to capacity. The liquid from this tank can be recycled back to these tanks, released directly to the environment via the waste monitor tank or processed through demineralizers prior to release from the plant.

The decontamination pit collection tank collects liquid from the Fuel Handling Building sumps, the Radiological Maintenance Building drains, excess waste holdup tank sump, excess waste holdup area sump and decontamination pit drains. If the activity in this tank liquid is such that the discharge limits cannot be met without cleanup, the liquid is processed through demineralizers and released under controlled conditions via the liquid effluents from nuclear plant to penstock system.

The system also normally receives liquid waste from the nuclear sampling system waste pump. In addition, the Turbine Building sump discharge will be directed to the excess liquid waste system if excessive radioactive discharge is detected.

System Evaluation Boundary

The evaluation boundary for the excess liquid waste system components subject to aging management review includes nonsafety-related components that retain water in buildings containing safety-related components.

System Intended Functions

The excess liquid waste system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the excess liquid waste system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

FSAR References

Additional details of the excess liquid waste system can be found in the FSAR, Section 11.2.2.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the excess liquid waste system are listed below:

SLR-302-734

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-12, Excess Liquid Waste.

The aging management review results for these component types are indicated in Table 3.3.2-12, Auxiliary Systems - Excess Liquid Waste - Aging Management Evaluation.

2.3.3.13 Fire Service

System Description

The fire service system is designed to ensure adequate fire protection for each fire hazard. The system provides fire detection, audible and visual alarms and extinguishment. The system includes motor-driven and engine-driven fire pumps that provide water to hydrants, hose stations, and sprinkler systems. The system also includes carbon dioxide suppression and Halon suppression systems. The fire service system can also supply cooling water to the diesel generators.

System Evaluation Boundary

The evaluation boundary for the fire service system components subject to aging management review includes safety-related containment penetration piping and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components. The electric and diesel-driven fire pumps and jockey pump are subject to aging management review. The diesel fire pump engine exhaust and fuel oil supply components outside of the skid are subject to aging management review. The water supply from the fire pumps, via the yard loop to applicable hydrants, hose reels, and sprinkler systems are subject to aging management review. Water suppression piping within the Auxiliary Service Building is not credited for NFPA-805, but is subject to aging management review to maintain yard loop integrity. The low pressure carbon dioxide tank and supply piping components are subject to aging management review.

Portions of the water suppression system are not credited with 10 CFR 50.48 compliance and are not within-scope, as shown on the highlighted SLR boundary drawings. The Halon systems are not credited with 10 CFR 50.48 compliance and are not within-scope.

Fire doors are addressed in structural commodities. Fire dampers are addressed in the air handling system. Smoke detectors are active instruments not subject to aging management review.

System Intended Functions

The fire service system performs the following safety-related functions: The system provides containment isolation. Therefore, the fire service system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The fire service system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the fire service system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The fire service system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the fire service system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the fire service system can be found in the FSAR, Section 9.5.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the fire service system are listed below:

SLR-302-231 Sh. 1

SLR-302-231 Sh. 2

SLR-302-231 Sh. 3

SLR-302-231 Sh. 4

SLR-302-231 Sh. 5

SLR-302-232

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-13, Fire Service.

The aging management review results for these component types are indicated in Table 3.3.2-13, Auxiliary Systems - Fire Service - Aging Management Evaluation.

2.3.3.14 Fuel Handling

System Description

The fuel handling system consists of the equipment needed for transporting and handling fuel. A fuel transfer tube connects the Reactor Building refueling canal and the Fuel Handling Building fuel transfer canal. This tube is fitted with a blind flange on the refueling canal end and a gate valve on the fuel transfer canal end. This blind flange is always in place, except during refueling, to ensure containment integrity. The fuel transfer tube and associated penetration sleeve are required to maintain pressure boundary integrity. The system includes the reactor cavity seal ring. The reactor cavity seal ring is removed during normal operations and is installed during refueling operations to retain water within the refueling cavity.

System Evaluation Boundary

The evaluation boundary for the fuel handling system components subject to aging management review includes the safety-related fuel transfer tube assembly, fuel pool gate seals and associated air piping components; the nonsafety-related reactor cavity seal ring; and the hydraulic piping components above the pool water line associated with the fuel transfer upenders that retain water in buildings containing safety-related components.

The safety-related fuel pool gate seal air supply piping and valves, and the attached nonsafety-related piping and valves that provide support are subject to aging management and are all mounted on the fuel pool gates up to but not including flexible hoses. The fuel pool gate seals and air supplies, and the upender hydraulic components do not appear on LR drawings.

The fuel pool gates are addressed in the structural section of the application. The fuel transfer tube gate valve is addressed with the spent fuel cooling system. Cranes and hoists within the scope of subsequent license renewal are addressed in the materials handling system.

System Intended Functions

The fuel handling system performs the following safety-related functions: The system provides containment isolation and provides the capability to isolate the spent fuel pool from the cask area and transfer canal. Therefore, the fuel handling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The fuel handling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. The system also provides a pressure boundary to retain inventory in the refueling cavity during refueling. Therefore, the fuel handling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and for pressure boundary integrity.

FSAR References

Additional details of the fuel handling system can be found in the FSAR, Sections 3.8.1.1.2.2, 6.2.6.2.2.1, and 9.1.4, Figures 3.8-16 and 9.1-7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the fuel handling system are listed below:

SLR-302-651

SLR-302-715

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-14, Fuel Handling.

The aging management review results for these component types are indicated in Table 3.3.2-14, Auxiliary Systems - Fuel Handling - Aging Management Evaluation.

2.3.3.15 Gaseous Waste Processing

System Description

The gaseous waste processing system removes fission product gases from the reactor coolant in the volume control tank. The system also collects gases from the boron recycle and waste evaporators, reactor coolant drain tank, recycle holdup tanks and reactor vessel. The system has capacity for long term storage.

System Evaluation Boundary

The evaluation boundary for the gaseous waste processing system components subject to aging management review includes the safety-related hydrogen recombiner cooler condenser, piping that provides a safety-related pressure boundary for the component cooling and chemical and volume control systems, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The gaseous waste processing system performs the following safety-related functions: The system provides a safety-related pressure boundary for the component cooling and chemical and volume control systems. Therefore, the gaseous waste processing system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The gaseous waste processing system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the gaseous waste processing system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

FSAR References

Additional details of the gaseous waste processing system can be found in the FSAR, Section 11.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the gaseous waste processing system are listed below:

SLR-302-741

SLR-302-742

SLR-302-743

SLR-302-744

SLR-302-745

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-15, Gaseous Waste Processing.

The aging management review results for these component types are indicated in Table 3.3.2-15, Auxiliary Systems - Gaseous Waste Processing - Aging Management Evaluation.

2.3.3.16 Hydrogen Removal, Post Accident

System Description

The hydrogen removal – post accident system (also called the combustible gas control system, or the post-accident hydrogen control system) provides control of combustible hydrogen concentrations in the Reactor Building following a loss-of-coolant accident (LOCA). The system uses electric hydrogen recombiners as a primary means of reducing hydrogen concentrations, while a purge system is provided as a backup to the recombiners. Hydrogen analyzers and sampling equipment enable monitoring of hydrogen concentration.

System Evaluation Boundary

The evaluation boundary for the hydrogen removal – post accident system components subject to aging management review includes the safety-related hydrogen recombiners, hydrogen sampling and analyzer components, safety-related containment penetration piping components, and nonsafety-related components that provide support to directly-connected safety-related components. The passive pressure boundary components within the hydrogen analyzers are subject to aging management review but are not shown on license renewal boundary drawings. Thermal insulation on safety-related heat traced components is also subject to aging management review.

System Intended Functions

The hydrogen removal – post accident system performs the following safety-related functions: The system provides containment isolation and controls hydrogen concentration within limits in the Reactor Building. Therefore, the hydrogen removal – post accident system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The hydrogen removal – post accident system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the hydrogen removal – post accident system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for structural integrity.

The hydrogen removal – post accident system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the hydrogen removal – post accident system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the hydrogen removal – post accident system can be found in the FSAR, Section 6.2.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the hydrogen removal, post accident system are listed below:

SLR-302-861

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-16, Hydrogen Removal, Post Accident.

The aging management review results for these component types are indicated in Table 3.3.2-16, Auxiliary Systems - Hydrogen Removal, Post Accident - Aging Management Evaluation.

2.3.3.17 Incore Instrumentation

System Description

The incore instrumentation system provides reactor core performance information in the form of neutron flux distribution data. The system consists of thermocouples positioned to measure fuel assembly coolant outlet temperature; and retractable flux thimble tubes which are inserted through bottom mounted instrumentation guide tubes that penetrate the reactor vessel bottom head and then through selected fuel assembles, moveable incore neutron detectors which are inserted into the thimbles, a seal table with seal assemblies/fittings, and isolation valves. The nonsafety-related isolation valves normally do not normally provide a reactor coolant system pressure boundary but are designed to be closed in the event of a leak in the thimble tubes.

System Evaluation Boundary

The evaluation boundary for the incore instrumentation system components subject to aging management review includes only the flux thimble tube isolation valves. The valves are not normally wetted, and do not rely on directly attached piping for support.

The flux thimble tubes are evaluated with the reactor vessel internals system, and the bottom mounted instrumentation guide tubes, seal table and seal table fittings are evaluated with the reactor vessel system. The detectors and drive cables are active components, not subject to aging management review.

System Intended Functions

The incore instrumentation system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the incore instrumentation system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for reactor coolant pressure boundary integrity.

The incore instrumentation system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the incore instrumentation system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the incore instrumentation system can be found in the FSAR, Sections 4.4.5.1 and 7.7.1.9.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the incore instrumentation system.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-17, Incore Instrumentation.

The aging management review results for these component types are indicated in Table 3.3.2-17, Auxiliary Systems - Incore Instrumentation - Aging Management Evaluation.

2.3.3.18 Industrial Cooler

System Description

The industrial cooler system is a closed-loop cooling system. During normal plant operation, this system supplies water to the cooling coils of the Reactor Building (RB) cooling units, the digital rod position indication data cabinet cooling units, the boron thermal regeneration system chiller condenser, the RB air compressors, and the RB air dryers. During post-accident conditions or following a loss of off-site power, the RB cooling units are cooled by water from the service water system. The activation of an engineered safety features actuation system signal automatically transfers the source of cooling water for the RB cooling units.

System Evaluation Boundary

The evaluation boundary for the industrial cooler system components subject to aging management review includes nonsafety-related components that retain water in buildings containing safety-related components. The safety-related Reactor Building temperature elements are active components and not subject to aging management review.

System Intended Functions

The industrial cooler system performs the following safety-related function: The system provides non-EQ safety-related instrumentation for Reactor Building temperature monitoring. Therefore, the industrial cooler system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The industrial cooler system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the industrial cooler system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

FSAR References

Additional details of the industrial cooler system can be found in the FSAR, Section 9.4.7.2.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the industrial cooler system are listed below:

SLR-302-851 Sh.1

SLR-302-851 Sh.2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-18, Industrial Cooler.

The aging management review results for these component types are indicated in Table 3.3.2-18, Auxiliary Systems - Industrial Cooler - Aging Management Evaluation.

2.3.3.19 Instrument Air

System Description

The instrument air system provides clean, dry air for instruments and controls. The instrument air system includes the Reactor Building instrument air system described in the FSAR. The system can also supply breathing air, when required. This system is nonsafety-related except for the containment isolation valves and associated piping; and air accumulators and associated piping components that provide a safety-related backup compressed air source for two pressurizer power operated relief valves that may be used for mitigation of design basis events or for post-fire safe shutdown.

System Evaluation Boundary

The evaluation boundary for the instrument air system components subject to aging management review includes the safety-related containment penetration piping components, and backup compressed air accumulators and piping components associated with the pressurizer power operated relief valves; portable air bottles, valves and hoses for local operation of select valves; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

Backup air accumulators for select air-operated valves in the air handling, component cooling, emergency feedwater, feedwater, main steam, and service water systems are addressed within those parent systems.

System Intended Functions

The instrument air system performs the following safety-related functions: The system provides containment isolation and provides a backup source of compressed air for operation of reactor coolant system pressurizer power operated relief valves. Therefore, the instrument air system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The instrument air system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the instrument air system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The instrument air system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Environmental Qualification (10 CFR 50.49). Therefore, the instrument air system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the instrument air system can be found in the FSAR, Sections 5.5.7.1.3.4 and 9.3.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the instrument air system are listed below:

SLR-302-273

SLR-302-274

SLR-817-130

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-19, Instrument Air.

The aging management review results for these component types are indicated in Table 3.3.2-19, Auxiliary Systems - Instrument Air - Aging Management Evaluation.

2.3.3.20 Leak Detection

System Description

The leak detection system provides inputs to the plant annunciator system when leakage of liquids or steam from system piping and/or components is detected. Automatic leak isolation functions such as pump tripping and valve closing are provided in certain critical systems through instrumentation and control functions of the leak detection system. The following systems are monitored:

- Reactor coolant pressure boundary
- Engineered Safety Features Systems (reactor building spray, residual heat removal, and safety injection) in the Auxiliary Building
- Feedwater system (Intermediate Building flood protection)
- Chemical and volume control system and auxiliary steam system (Auxiliary Building ambient temperature control system)
- Circulating water system (Turbine Building flood protection)
- Chemical and volume control system, waste processing system, and boron recycle system (valve stem leakoff)

The system is primarily comprised of instrumentation installed in the monitored systems or associated leakage paths with only a small number of passive mechanical piping components.

System Evaluation Boundary

The evaluation boundary for the leak detection system components subject to aging management review includes nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The leak detection system performs the following safety-related functions: The system provides safety-related instrumentation. Therefore, the leak detection system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The leak detection system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the leak detection system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The leak detection system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the leak detection system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the leak detection system can be found in the FSAR, Sections 5.2.7 and 7.6.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the leak detection system are listed below:

SLR-302-812

SLR-302-824

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-20, Leak Detection.

The aging management review results for these component types are indicated in Table 3.3.2-20, Auxiliary Systems - Leak Detection - Aging Management Evaluation.

2.3.3.21 Liquid Effluents From Nuclear Plant to Penstock

System Description

The liquid effluents from nuclear plant to penstock system works in concert with the excess liquid waste and the liquid waste processing systems. Together, these systems are described as the liquid waste processing system in the FSAR. The liquid effluents from nuclear plant to penstock system provides a flowpath for the controlled discharge of liquid radioactive waste to the Fairfield Pumped Storage Facility penstocks. The system consists of piping components between the Auxiliary Building and the discharge point.

System Evaluation Boundary

The evaluation boundary for the liquid effluents from nuclear plant to penstock system components subject to aging management review includes the nonsafety-related components that retain water in buildings containing safety-related components.

System Intended Functions

The liquid effluents from nuclear plant to penstock system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the liquid effluents from nuclear plant to penstock system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

FSAR References

Additional details of the liquid effluents from nuclear plant to penstock system can be found in the FSAR, Section 11.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the liquid effluents from nuclear plant to penstock system are listed below:

SLR-302-362

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-21, Liquid Effluents From Nuclear Plant to Penstock.

The aging management review results for these component types are indicated in Table 3.3.2-21, Auxiliary Systems - Liquid Effluents From Nuclear Plant to Penstock - Aging Management Evaluation.

2.3.3.22 Liquid Waste Processing

System Description

The liquid waste processing system collects, segregates and processes reactor-grade and non-reactor-grade liquid wastes produced during plant operation, refueling and maintenance activities. The processed reactor-grade stream is recycled for plant use, while non-reactor-grade liquids are processed and disposed of in accordance with applicable NRC regulations.

The liquid waste processing system is designed to control and minimize releases of radioactivity to the environment. The system does not perform any safety-related functions related to the processing of water. However, two of the lines in the system penetrate containment and therefore, portions of the system are safety-related. The system also includes components that maintain a safety-related pressure boundary with the component cooling and spent fuel cooling systems.

The FSAR discussion of the liquid waste processing system includes the excess liquid waste system and the liquid effluents from nuclear plant to penstock system.

System Evaluation Boundary

The evaluation boundary for the liquid waste processing system components subject to aging management review includes safety-related containment penetration piping components and safety-related valves and heat exchangers that provide integrity for attached systems; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

The safety-related heat exchangers in the system provide integrity for the component cooling system but cooling of waste processing flowpaths is not an intended function, so the heat exchangers do not perform a heat transfer function.

System Intended Functions

The liquid waste processing system performs the following safety-related functions: The system provides containment isolation and provides a safety-related pressure boundary for the component cooling water and spent fuel cooling systems. Therefore, the liquid waste processing system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The liquid waste processing system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the liquid waste processing system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The liquid waste processing system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the liquid waste processing system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the liquid waste processing system can be found in the FSAR, Section 11.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the liquid waste processing system are listed below:

SLR-09-238

SLR-302-735

SLR-302-736

SLR-302-737

SLR-302-738

SLR-302-825

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-22, Liquid Waste Processing.

The aging management review results for these component types are indicated in Table 3.3.2-22, Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation.

2.3.3.23 Material Handling

System Description

The material handling system is comprised of load handling cranes and hoists. The following cranes and hoists that are within the scope of NUREG-0612 are within-scope for subsequent license renewal:

- 125/15-ton fuel handling building crane (spent fuel cask handling crane)
- 3-ton fuel handling building hoist (transfer canal gate hoist)
- ‘B' loop auxiliary crane
- Reactor building polar crane

Other cranes and hoists that are not within the scope of NUREG-0612 but are used to lift irradiated fuel assemblies are also within the scope of subsequent license renewal. As a result, the following cranes and hoists are within-scope for subsequent license renewal:

- Reactor cavity manipulator crane (refueling machine)
- Spent fuel pit bridge crane (fuel handling machine)

System Evaluation Boundary

The evaluation boundary for the material handling system components subject to aging management review includes load-bearing elements that support the load in a passive manner. These include the structural bolting, beams, girders, plates, rails and retaining clips associated with the cranes and hoists listed above.

System Intended Functions

The material handling system performs the following safety-related functions: The reactor building polar crane and 125/15-ton fuel handling building crane (spent fuel cask handling crane) are safety-related components designed to remain intact during seismic events. Therefore, the material handling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The material handling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the material handling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for structural support.

FSAR References

Additional details of the material handling system can be found in the FSAR, Sections 3.12, 9.1.4.2.2, and 9.1.4.3.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the material handling system.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-23, Material Handling.

The aging management review results for these component types are indicated in Table 3.3.2-23, Auxiliary Systems - Material Handling - Aging Management Evaluation.

2.3.3.24 Nitrogen Blanketing

System Description

The nitrogen blanketing system provides pressurized nitrogen to hose connections located inside containment, and to feedwater heaters and a deaerator to support steam generator and secondary side layup conditions.

System Evaluation Boundary

The evaluation boundary for the nitrogen blanketing system components subject to aging management review includes the safety-related penetration piping components, and nonsafety-related components that provide support to directly-connected safety-related components.

System Intended Functions

The nitrogen blanketing system performs the following safety-related functions: The system provides containment isolation. Therefore, the nitrogen blanketing system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The nitrogen blanketing system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the nitrogen blanketing system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for structural integrity.

FSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the nitrogen blanketing system are listed below:

SLR-302-311

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-24, Nitrogen Blanketing.

The aging management review results for these component types are indicated in Table 3.3.2-24, Auxiliary Systems - Nitrogen Blanketing - Aging Management Evaluation.

2.3.3.25 Nuclear and Miscellaneous Drains

System Description

The nuclear and miscellaneous drains system (called equipment and floor drainage system in FSAR 9.3.3) provides drainage paths for potentially radioactive and non-radioactive liquid wastes through separate subsystems. The system includes component drain piping, floor and roof drain piping, sump pumps and associated piping components. The system generates alarms to indicate excessive input flow. In addition, the system provides pump trip functions to prevent flooding in the Control and Intermediate Buildings.

System Evaluation Boundary

The evaluation boundary for the nuclear and miscellaneous drains system components subject to aging management review includes safety-related containment penetration piping components; nonsafety related piping that provides a drain path for the reactor cavity and that provide steam propagation barriers between harsh and mild environment areas (not shown on SLR boundary drawings), and nonsafety-related components that retain water in buildings containing safety-related components. There are no passive mechanical components that support the pump trip and valve closure flood mitigation function. Floor and roof drain piping and sanitary drain piping within buildings containing safety-related components are subject to aging management review but do not appear on SLR boundary drawings.

System Intended Functions

The nuclear and miscellaneous drains system performs the following safety-related function: The system provides containment isolation. Therefore, the nuclear drains system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The nuclear and miscellaneous drains system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. The system drains leakage and generates pump trip signals to mitigate internal flooding, provides a flowpath to drain containment spray water from the reactor cavity, and provides steam propagation barriers. Therefore, the nuclear and miscellaneous drains system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for flowpath integrity, instrumentation signals, area isolation, spatial interaction, and structural integrity.

The nuclear and miscellaneous drains system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Environmental Qualification (10 CFR 50.49). Therefore, the nuclear and miscellaneous drains system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the nuclear and miscellaneous drains system can be found in the FSAR, Sections 6.2.2.3.1.1 and 9.3.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the nuclear and miscellaneous drains system are listed below:

SLR-302-352

SLR-302-821

SLR-302-822

SLR-302-823

SLR-302-824

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-25, Nuclear and Miscellaneous Drains.

The aging management review results for these component types are indicated in Table 3.3.2-25, Auxiliary Systems - Nuclear and Miscellaneous Drains - Aging Management Evaluation.

2.3.3.26 Nuclear Sampling

System Description

The nuclear sampling system provides for centralized sampling of primary system fluids and permits continuous steam generator blowdown flow to the turbine cycle sampling system for analysis. Samples requiring cooling and depressurization, and which are or could be radioactive are piped to the nuclear sampling room. The system also monitors primary letdown water for failed fuel detection.

System Evaluation Boundary

The evaluation boundary for the nuclear sampling system components subject to aging management review includes safety-related piping components associated with containment penetrations or connected to safety-related systems; safety-related heat exchangers (sample coolers) that provide a pressure boundary for the component cooling system; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or steam in buildings containing safety-related components.

System Intended Functions

The nuclear sampling system performs the following safety-related functions: The system provides safety-related pressure boundaries for attached systems and provides containment isolation. Therefore, the nuclear sampling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The nuclear sampling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the nuclear sampling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The nuclear sampling system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the nuclear sampling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the nuclear sampling system can be found in the FSAR, Section 9.3.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the nuclear sampling system are listed below:

SLR-302-182

SLR-302-771

SLR-302-772

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-26, Nuclear Sampling.

The aging management review results for these component types are indicated in Table 3.3.2-26, Auxiliary Systems - Nuclear Sampling - Aging Management Evaluation.

2.3.3.27 Radiation Monitoring

System Description

The radiation monitoring system includes radiation monitors and provides for analysis of samples that are used to monitor process and effluent streams to record and control releases of radioactive materials generated as a result of normal operations, anticipated operational occurrences, and postulated accidents.

System Evaluation Boundary

The evaluation boundary for the radiation monitoring system components subject to aging management review includes safety-related radiation monitor sample flowpath components, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The radiation monitoring system performs the following safety-related functions: The system maintains safety-related pressure boundaries for the component cooling, spent fuel cooling, and chemical and volume control systems. Therefore, the radiation monitoring system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The radiation monitoring system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the radiation monitoring system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The radiation monitoring system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the radiation monitoring system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the radiation monitoring system can be found in the FSAR, Section 11.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the radiation monitoring system are listed below:

SLR-806-001

SLR-806-005

SLR-806-006

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-27, Radiation Monitoring.

The aging management review results for these component types are indicated in Table 3.3.2-27, Auxiliary Systems - Radiation Monitoring - Aging Management Evaluation.

2.3.3.28 Radwaste Solidification & Solids Handling

System Description

The radwaste solidification and solids handling system (called the solid waste system in the FSAR) is designed to package and/or solidify radioactive wastes for shipment to an approved offsite facility. The mechanical fluid components in the system are located in the Auxiliary Building. The system is not credited with any safety-related or regulated event function.

System Evaluation Boundary

The evaluation boundary for the radwaste solidification and solids handling system components subject to aging management review includes nonsafety-related components that retain water in buildings containing safety-related components.

System Intended Functions

The radwaste solidification and solids handling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the radwaste solidification and solids handling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

FSAR References

Additional details of the radwaste solidification & solids handling system can be found in the FSAR, Section 11.5.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the radwaste solidification & solids handling system are listed below:

SLR-302-732

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-28, Radwaste Solidification & Solids Handling.

The aging management review results for these component types are indicated in Table 3.3.2-28, Auxiliary Systems - Radwaste Solidification & Solids Handling - Aging Management Evaluation.

2.3.3.29 Reactor Building Cooling Unit Drains

System Description

The reactor building cooling unit drains system provides for drainage of condensation from the safety-related demister banks and plenums of the reactor building cooling units to nuclear drains system floor drains.

System Evaluation Boundary

The evaluation boundary for the reactor building cooling unit drains system components subject to aging management review includes the safety-related piping that drains the reactor building cooling units.

System Intended Functions

The reactor building cooling unit drains system performs the following safety-related functions: The system provides piping integrity for the reactor building cooling unit condensation drains. Therefore, the reactor building cooling unit drains system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

FSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the reactor building cooling unit drains system are listed below:

SLR-302-824

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-29, Reactor Building Cooling Unit Drains.

The aging management review results for these component types are indicated in Table 3.3.2-29, Auxiliary Systems - Reactor Building Cooling Unit Drains - Aging Management Evaluation.

2.3.3.30 Reactor Building Leak Rate Testing

System Description

The Reactor Building leak rate testing system provides piping connections and instrumentation to support containment leakage testing in accordance with 10 CFR 50, Appendix J.

System Evaluation Boundary

The evaluation boundary for the Reactor Building leak rate testing system components subject to aging management review includes the safety-related containment penetration piping, and nonsafety-related components that provide support to directly-connected safety-related components.

System Intended Functions

The Reactor Building leak rate testing system performs the following safety-related functions: The system provides containment isolation. Therefore, the Reactor Building leak rate testing system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Reactor Building leak rate testing system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the Reactor Building leak rate testing system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for structural integrity.

FSAR References

Additional details of the reactor building leak rate testing system can be found in the FSAR, Section 6.2.6.1.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the reactor building leak rate testing system are listed below:

SLR-302-811

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-30, Reactor Building Leak Rate Testing.

The aging management review results for these component types are indicated in Table 3.3.2-30, Auxiliary Systems - Reactor Building Leak Rate Testing - Aging Management Evaluation.

2.3.3.31 Reactor Makeup Water Supply

System Description

The reactor makeup water supply system provides for the storage of recycled primary coolant grade water. This system supplies makeup water to the chemical and volume control system, the spent fuel pool, the pressurizer relief tank; and provides flushing water to reactor auxiliary systems. The portion of the reactor makeup water supply system between the reactor makeup water storage tank and the chemical and volume control and spent fuel pool cooling systems is safety-related; the remaining portions of the system are nonsafety-related.

System Evaluation Boundary

The evaluation boundary for the reactor makeup water supply system components subject to aging management review includes the safety-related reactor makeup water storage tank and piping flowpaths from that tank through the reactor makeup water pumps to the chemical and volume control system and to the fuel pool cooling system; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components. Thermal insulation on the reactor makeup water storage tank and attached outdoor safety-related piping and level instrumentation is also subject to aging management review.

The reactor makeup water storage tank foundation is addressed in the structural section of this application.

System Intended Functions

The reactor makeup water supply system performs the following safety-related functions: the system provides makeup to the chemical and volume control system and to the spent fuel pool. Therefore, the reactor makeup water supply system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The reactor makeup water supply system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the reactor makeup water supply system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

FSAR References

Additional details of the reactor makeup water supply system can be found in the FSAR, Section 9.2.7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the reactor makeup water supply system are listed below:

SLR-302-791

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-31, Reactor Makeup Water Supply.

The aging management review results for these component types are indicated in Table 3.3.2-31, Auxiliary Systems - Reactor Makeup Water Supply - Aging Management Evaluation.

2.3.3.32 Service Water

System Description

The service water system provides water from the service water pond for cooling of the emergency diesel generators, component cooling heat exchangers, heating ventilating and air conditioning (HVAC) mechanical water chiller condensers, and Service Water Pumphouse cooling coils. During post-accident conditions, loss of offsite power or testing, the service water system cools the Reactor Building cooling units (RBCUs). In addition, this system is the backup water source for the emergency feedwater and component cooling water systems. The system consists of two independent full capacity loops with the capability of valving a third swing service water pump into either loop. The service water system is safety-related, and is designed such that a single failure does not cause loss of cooling to more than one of the redundant loops.

System Evaluation Boundary

The evaluation boundary for the service water system components subject to aging management review includes the safety-related pumps, piping, and components to each of the heat loads served by the system; safety-related backup air tank and associated piping components to the service water pond return isolation valves; safety-related traveling screens and trash racks located at the service water pump intake; and the safety-related piping which provides the intake from and discharge to the pond. The nonsafety-related components that provide support to directly-connected safety-related components, or that retain water, steam or oil in buildings containing safety-related components are also subject to aging management review. Thermal insulation on steel piping with internal lining in the Intermediate Building is also subject to aging management review.

System Intended Functions

The service water system performs the following safety-related functions: The system provides cooling water to the HVAC chiller condensers, diesel generator heat exchangers, component cooling heat exchangers, and RBCUs; provides containment isolation; and provides an emergency (back-up) water source for the emergency feedwater and component cooling water systems. Therefore, the service water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The service water system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the service water system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The service water system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the service water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the service water system can be found in the FSAR, Section 9.2.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the service water system are listed below:

SLR-14-094

SLR-302-221 Sh. 1

SLR-302-221 Sh. 2

SLR-302-222 Sh. 1

SLR-302-222 Sh. 2

SLR-302-222 Sh. 3

SLR-302-222 Sh. 4

SLR-302-322

SLR-54-660

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-32, Service Water.

The aging management review results for these component types are indicated in Table 3.3.2-32, Auxiliary Systems - Service Water - Aging Management Evaluation.

2.3.3.33 Spent Fuel Cooling

System Description

The spent fuel cooling system cools spent fuel pool water to remove decay heat from the spent fuel elements. This system also: (1) transfers water between the refueling water storage tank (RWST) and refueling cavity, (2) maintains purity and clarity of water in spent fuel pool and/or refueling cavity, (3) provides means for adding boric acid to spent fuel pool, (4) provides means for adding demineralized water to spent fuel pool, (5) monitors spent fuel coolant for excessive radioactivity due to defective fuel elements, (6) provides for filtering and/or demineralization to clean the water in the RWST, and (7) maintains a water shield above spent fuel elements to limit radiation levels in the area of the pool.

System Evaluation Boundary

The evaluation boundary for the spent fuel cooling system components subject to aging management review includes the piping and components in the cooling flowpath from the spent fuel pool through the spent fuel cooling pumps and heat exchangers and the return to the fuel pool. Also subject to aging management review are the nonsafety-related components that retain water in buildings containing safety-related components or that provide support to safety-related piping. This includes the fuel transfer canal gate valve. Thermal insulation on outdoor safety-related piping and refueling water storage tank instrumentation is also subject to aging management review.

The fuel pit liner and storage racks are evaluated in the structural section of the application. The refueling water storage tank is evaluated in the refueling water system.

System Intended Functions

The spent fuel cooling system performs the following safety-related functions: The system maintains spent fuel pool inventory for radiation shielding, removes heat from the spent fuel pool, and provides containment isolation. Therefore, the spent fuel cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The spent fuel cooling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the spent fuel cooling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The spent fuel cooling system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the spent fuel cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the spent fuel cooling system can be found in the FSAR, Section 9.1.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the spent fuel cooling system are listed below:

SLR-302-322

SLR-302-651

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-33, Spent Fuel Cooling.

The aging management review results for these component types are indicated in Table 3.3.2-33, Auxiliary Systems - Spent Fuel Cooling - Aging Management Evaluation.

2.3.3.34 Station Service Air

System Description

The station service air system provides compressed air for general plant use and is distributed via quick disconnect hose connections throughout the plant. The operation of this system is not required to mitigate the consequences of a loss-of-coolant accident or achieve a safe shutdown condition. This system is nonsafety-related except for piping and valves associated with the containment penetration, and with the personnel hatch and equipment hatch test piping components that provide containment integrity.

System Evaluation Boundary

The evaluation boundary for the station service air system components subject to aging management review includes the safety-related containment penetration, the personnel hatch and equipment hatch test piping components that provide containment integrity; and nonsafety-related components that provide support to directly-connected safety-related components.

System Intended Functions

The station service air system performs the following safety-related functions: The system provides containment isolation. Therefore, the station service air system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The station service air system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the station service air system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for structural integrity.

FSAR References

Additional details of the station service air system can be found in the FSAR, Sections 6.2.6.2.1.3 and 9.3.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the station service air system are listed below:

SLR-302-241

SLR-302-242

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-34, Station Service Air.

The aging management review results for these component types are indicated in Table 3.3.2-34, Auxiliary Systems - Station Service Air - Aging Management Evaluation.

2.3.3.35 Thermal Regeneration

System Description

The thermal regeneration system (called boron thermal regeneration in the FSAR) accepts borated water letdown from the reactor coolant system (via the chemical and volume control system) and returns it with boron removed as necessary based on operating requirements. The load following capabilities of the (boron) thermal regeneration system, which were part of the original design, were removed by plant modification. The deborating demineralizers in the system continue to be used to reduce reactor coolant boron concentration near the end of core life. The thermal regeneration system is also used to cool the letdown flow for enhanced reactor coolant pump seal performance, and to clean up the reactor coolant system before shutting down the reactor.

System Evaluation Boundary

The evaluation boundary for the thermal regeneration system components subject to aging management review includes the safety-related flowpath from the chemical and volume control system through heat exchangers, demineralizers and piping components back to the chemical and volume control system; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or oil in buildings containing safety-related components.

System Intended Functions

The thermal regeneration system performs the following safety-related functions: The system provides a safety-related pressure boundary for the chemical and volume control system and provides non-EQ safety-related instrumentation. Therefore, the thermal regeneration system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The thermal regeneration system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the thermal regeneration system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

FSAR References

Additional details of the thermal regeneration system can be found in the FSAR, Section 9.3.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the thermal regeneration system are listed below:

SLR-302-676

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-35, Thermal Regeneration.

The aging management review results for these component types are indicated in Table 3.3.2-35, Auxiliary Systems - Thermal Regeneration - Aging Management Evaluation.

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Screening Results Tables: Auxiliary Systems

Table 2.3.3-1 Air Handling and Local Ventilation and Cooling

Component Type	Intended Function(s)
Accumulator (control room isolation damper backup air)	Pressure Boundary
Air handling unit (battery room cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (battery room cooling coil header)	Pressure Boundary
Air handling unit (battery room cooling drip pan)	Pressure Boundary
Air handling unit (battery room filter, cooler, damper, and fan plenum)	Pressure Boundary
Air handling unit (BOP charger area cooling coil header)	Leakage Boundary (Spatial)
Air handling unit (BOP charger area cooling coil)	Leakage Boundary (Spatial)
Air handling unit (BOP charger area drip pan)	Leakage Boundary (Spatial)
Air handling unit (charging/SI pump room cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (charging/SI pump room cooling coil header)	Pressure Boundary
Air handling unit (charging/SI pump room drip pan)	Pressure Boundary
Air handling unit (charging/SI pump room filter, cooler, and fan plenum)	Pressure Boundary
Air handling unit (computer room cooling coil header)	Leakage Boundary (Spatial)
Air handling unit (computer room cooling coil)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-1 Air Handling and Local Ventilation and Cooling

Component Type	Intended Function(s)
Air handling unit (computer room cooling drip pan)	Leakage Boundary (Spatial)
Air handling unit (control rod position data cabinet cooling coil header)	Leakage Boundary (Spatial)
Air handling unit (control rod position data cabinet cooling coil)	Leakage Boundary (Spatial)
Air handling unit (control rod position data cabinet cooling drip pan)	Leakage Boundary (Spatial)
Air handling unit (control room cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (control room cooling coil header)	Pressure Boundary
Air handling unit (control room cooling drip pan)	Pressure Boundary
Air handling unit (control room filter, cooler, damper, and fan plenum)	Pressure Boundary
Air handling unit (controlled access cooling coil header)	Leakage Boundary (Spatial)
Air handling unit (controlled access cooling coil)	Leakage Boundary (Spatial)
Air handling unit (controlled access cooling drip pan)	Leakage Boundary (Spatial)
Air handling unit (CRDM switchgear room cooling coil header)	Leakage Boundary (Spatial)
Air handling unit (CRDM switchgear room cooling coil)	Leakage Boundary (Spatial)
Air handling unit (CRDM switchgear room drip pan)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-1 Air Handling and Local Ventilation and Cooling

Component Type	Intended Function(s)
Air handling unit (emergency feedwater pump area cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (emergency feedwater pump area cooling coil header)	Pressure Boundary
Air handling unit (emergency feedwater pump area drip pan)	Pressure Boundary
Air handling unit (emergency feedwater pump area filter, cooler, and fan plenum)	Pressure Boundary
Air handling unit (ESF switchgear room cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (ESF switchgear room cooling coil header)	Pressure Boundary
Air handling unit (ESF switchgear room drip pan)	Pressure Boundary
Air handling unit (ESF switchgear room filter, cooler, and fan plenum)	Pressure Boundary
Air handling unit (Fuel Handling Building supplemental cooling coil header)	Leakage Boundary (Spatial)
Air handling unit (Fuel Handling Building supplemental cooling coil)	Leakage Boundary (Spatial)
Air handling unit (Fuel Handling Building supplemental cooling drip pan)	Leakage Boundary (Spatial)
Air handling unit (MCC switchgear cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (MCC switchgear drip pan)	Pressure Boundary
Air handling unit (MCC switchgear filter, cooler, and fan plenum)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-1 Air Handling and Local Ventilation and Cooling

Component Type	Intended Function(s)
Air handling unit (MCC switchgear filter, cooling coil header)	Pressure Boundary
Air handling unit (Reactor Building cooling unit - cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (Reactor Building cooling unit - cooling coil header)	Pressure Boundary
Air handling unit (Reactor Building cooling unit - filter, damper, cooler, and fan plenum)	Pressure Boundary
Air handling unit (relay room cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (relay room cooling coil header)	Pressure Boundary
Air handling unit (relay room cooling drip pan)	Pressure Boundary
Air handling unit (relay room filter, cooler, damper, and fan plenum)	Pressure Boundary
Air handling unit (RHR/spray pump room cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (RHR/spray pump room drip pan)	Pressure Boundary
Air handling unit (RHR/spray pump room filter, cooler, and fan plenum)	Pressure Boundary
Air handling unit (RHR/spray pump room filter, cooling coil header)	Pressure Boundary
Air handling unit (SAS/computer room cooling coil header)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-1 Air Handling and Local Ventilation and Cooling

Component Type	Intended Function(s)
Air handling unit (SAS/computer room cooling coil)	Leakage Boundary (Spatial)
Air handling unit (SAS/computer room cooling drip pan)	Leakage Boundary (Spatial)
Air handling unit (service water booster pump area cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (service water booster pump area cooling coil header)	Pressure Boundary
Air handling unit (service water booster pump area drip pan)	Pressure Boundary
Air handling unit (service water booster pump area filter, cooler, and fan plenum)	Pressure Boundary
Air handling unit (speed switch room cooling coil and fin)	Heat Transfer, Pressure Boundary
Air handling unit (speed switch room cooling coil header)	Pressure Boundary
Air handling unit (speed switch room drip pan)	Pressure Boundary
Air handling unit (speed switch room filter, cooler, and fan plenum)	Pressure Boundary
Damper housing	Pressure Boundary, Structural Integrity (Attached)
Duct	Fire Barrier, Pressure Boundary, Structural Integrity (Attached)
Expansion joint	Pressure Boundary
Fan housing (battery room exhaust)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-1 Air Handling and Local Ventilation and Cooling

Component Type	Intended Function(s)
Fan housing (control room emergency filtration)	Pressure Boundary
Fan housing (diesel generator room)	Pressure Boundary
Fan housing (Fuel Handling Building)	Pressure Boundary
Fan housing (service water pump house)	Pressure Boundary
Filter housing (Auxiliary Building)	Structural Integrity (Attached)
Filter housing (control room)	Pressure Boundary
Filter housing (Fuel Handling Building)	Pressure Boundary
Filter rack	Structural Support
Fire damper assembly	Fire Barrier, Pressure Boundary, Structural Integrity (Attached)
Heat exchanger (CRDM cooler - cooling coil)	Leakage Boundary (Spatial)
Heat exchanger (CRDM cooler - drip pan)	Leakage Boundary (Spatial)
Heat exchanger (CRDM cooler - header)	Leakage Boundary (Spatial)
Heater coil housing	Pressure Boundary
Humidifier reservoir	Leakage Boundary (Spatial)
HVAC bolting	Fire Barrier, Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components	Pressure Boundary, Structural Integrity (Attached)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-1 Air Handling and Local Ventilation and Cooling

Component Type	Intended Function(s)
Valve body	Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-1, Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-2 Auxiliary Coolant

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (CRDM cooling water)	Leakage Boundary (Spatial)
Tank (CRDM cooling water chemical feed)	Leakage Boundary (Spatial)
Tank (CRDM cooling water expansion)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-2, Auxiliary Systems - Auxiliary Coolant - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-3 Boron Recycle

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Demineralizer shell	Leakage Boundary (Spatial)
Eductor	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (concentrates sample cooler - channel)	Pressure Boundary
Heat exchanger (concentrates sample cooler - shell)	Pressure Boundary
Heat exchanger (concentrates sample cooler - tube and tubesheet)	Pressure Boundary
Heat exchanger (distillate cooler - channel)	Pressure Boundary
Heat exchanger (distillate cooler - shell)	Pressure Boundary
Heat exchanger (distillate cooler - tube and tubesheet)	Pressure Boundary
Heat exchanger (evaporator - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator - shell)	Leakage Boundary (Spatial)
Heat exchanger (evaporator condenser - channel)	Pressure Boundary
Heat exchanger (evaporator condenser - shell)	Pressure Boundary
Heat exchanger (evaporator condenser - tube and tubesheet)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-3 Boron Recycle

Component Type	Intended Function(s)
Heat exchanger (evaporator feed preheater - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator feed preheater - shell)	Leakage Boundary (Spatial)
Heat exchanger (evaporator vent condenser - channel)	Pressure Boundary
Heat exchanger (evaporator vent condenser - shell)	Pressure Boundary
Heat exchanger (evaporator vent condenser - tube and tubesheet)	Pressure Boundary
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Piping, piping components (chemical addition)	Leakage Boundary (Spatial)
Pump casing (evaporator concentrates)	Leakage Boundary (Spatial)
Pump casing (evaporator distillate)	Leakage Boundary (Spatial)
Pump casing (evaporator feed)	Leakage Boundary (Spatial)
Rupture disc	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Tank (evaporator reagent)	Leakage Boundary (Spatial)
Tank (recycle hold-up)	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-3 Boron Recycle

Component Type	Intended Function(s)
Valve body	Leakage Boundary (Spatial), Pressure Boundary
Valve body (chemical addition)	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-3, Auxiliary Systems - Boron Recycle - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-4 Building Services

Component Type	Intended Function(s)
Piping, piping components	Pressure Boundary
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-4, Auxiliary Systems - Building Services - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-5 Chemical and Volume Control

Component Type	Intended Function(s)
Blender	Pressure Boundary
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Demineralizer shell	Pressure Boundary
Filter housing	Pressure Boundary
Filter housing (boric acid)	Pressure Boundary
Filter housing (charging pump lubricating oil)	Pressure Boundary
Filter housing (seal injection)	Pressure Boundary
Filter housing (seal return)	Pressure Boundary
Flexible hose	Leakage Boundary (Spatial), Pressure Boundary
Flow element	Pressure Boundary, Restricts Flow
Gearbox / oil sump (charging pump)	Pressure Boundary
Heat exchanger (charging pump oil - channel)	Pressure Boundary
Heat exchanger (charging pump oil - shell)	Pressure Boundary
Heat exchanger (charging pump oil - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (charging pump oil - tubesheet)	Pressure Boundary
Heat exchanger (excess letdown - channel)	Pressure Boundary
Heat exchanger (excess letdown - shell)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-5 Chemical and Volume Control

Component Type	Intended Function(s)
Heat exchanger (excess letdown - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (excess letdown - tubesheet)	Pressure Boundary
Heat exchanger (letdown - channel)	Pressure Boundary
Heat exchanger (letdown - shell)	Pressure Boundary
Heat exchanger (letdown - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (letdown - tubesheet)	Pressure Boundary
Heat exchanger (regenerative - channel)	Pressure Boundary
Heat exchanger (regenerative - shell)	Pressure Boundary
Heat exchanger (regenerative - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (regenerative - tubesheet)	Pressure Boundary
Heat exchanger (seal water - channel)	Pressure Boundary
Heat exchanger (seal water - shell)	Pressure Boundary
Heat exchanger (seal water - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (seal water - tubesheet)	Pressure Boundary
Insulation (containment penetration)	Thermal insulation
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components (Class 1 <NPS 4)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-5 Chemical and Volume Control

Component Type	Intended Function(s)
Pulsation dampener (alternate seal injection)	Pressure Boundary
Pump casing (alternate seal injection)	Pressure Boundary
Pump casing (boric acid)	Pressure Boundary
Pump casing (charging pump lubricating oil)	Pressure Boundary
Pump casing (charging)	Pressure Boundary
Sight glass	Leakage Boundary (Spatial), Pressure Boundary
Sight glass (body)	Leakage Boundary (Spatial), Pressure Boundary
Tank (boric acid batch - steam jacket)	Leakage Boundary (Spatial)
Tank (boric acid batch)	Leakage Boundary (Spatial)
Tank (boric acid)	Pressure Boundary
Tank (chemical mixing)	Leakage Boundary (Spatial)
Tank (resin fill)	Leakage Boundary (Spatial)
Tank (volume control)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Valve body (Class 1)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-5, Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-6 Chilled Water

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Compressor housing (chiller)	Pressure Boundary
Eductor (chilled water lubrication system)	Pressure Boundary
Filter housing (lube oil)	Pressure Boundary
Filter housing (refrigerant)	Pressure Boundary
Flow Element	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Heat exchanger (A and B chilled water condenser - channel)	Pressure Boundary
Heat exchanger (A and B chilled water condenser - fins)	Heat Transfer
Heat exchanger (A and B chilled water condenser - shell)	Pressure Boundary
Heat exchanger (A and B chilled water condenser - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (A and B chilled water condenser - tubesheet)	Pressure Boundary
Heat exchanger (A and B chilled water evaporator - channel)	Pressure Boundary
Heat exchanger (A and B chilled water evaporator - fins)	Heat Transfer
Heat exchanger (A and B chilled water evaporator - shell)	Pressure Boundary
Heat exchanger (A and B chilled water evaporator - tube)	Heat Transfer, Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-6 Chilled Water

Component Type	Intended Function(s)
Heat exchanger (A and B chilled water evaporator - tubesheet)	Pressure Boundary
Heat exchanger (C chilled water condenser - channel)	Pressure Boundary
Heat exchanger (C chilled water condenser - fins)	Heat Transfer
Heat exchanger (C chilled water condenser - shell)	Pressure Boundary
Heat exchanger (C chilled water condenser - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (C chilled water condenser - tubesheet)	Pressure Boundary
Heat exchanger (C chilled water evaporator - channel)	Pressure Boundary
Heat exchanger (C chilled water evaporator - fins)	Heat Transfer
Heat exchanger (C chilled water evaporator - shell)	Pressure Boundary
Heat exchanger (C chilled water evaporator - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (C chilled water evaporator - tubesheet)	Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (chemical feed)	Leakage Boundary (Spatial)
Pump casing (chilled water)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-6 Chilled Water

Component Type	Intended Function(s)
Pump casing (fluid ejector)	Pressure Boundary
Pump casing (lube oil)	Pressure Boundary
Sight glass	Leakage Boundary (Spatial), Pressure Boundary
Sight glass (body)	Leakage Boundary (Spatial), Pressure Boundary
Strainer body (chemical feed pump suction)	Leakage Boundary (Spatial)
Tank (chemical feed)	Leakage Boundary (Spatial)
Tank (chilled water expansion)	Pressure Boundary
Tank (chiller purge unit)	Pressure Boundary
Tank (lube oil sump)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-6, Auxiliary Systems - Chilled Water - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-7 Circulating Water

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Piping, piping components	Pressure Boundary
Traveling screen element	Filtration
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-7, Auxiliary Systems - Circulating Water - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-8 Component Cooling

Component Type	Intended Function(s)
Accumulator	Structural Integrity (Attached)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Pressure Boundary
Flow element	Pressure Boundary, Restricts Flow
Heat exchanger (component cooling - channel)	Pressure Boundary
Heat exchanger (component cooling - shell)	Pressure Boundary
Heat exchanger (component cooling - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (component cooling - tubesheet)	Pressure Boundary
Heat exchanger (pump motor cooler - channel)	Pressure Boundary
Heat exchanger (pump motor cooler - fins)	Heat Transfer
Heat exchanger (pump motor cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (pump motor cooler - tubesheet)	Pressure Boundary
Oil trap	Leakage Boundary (Spatial)
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-8 Component Cooling

Component Type	Intended Function(s)
Pump casing (chemical injection)	Leakage Boundary (Spatial)
Pump casing (component cooling booster)	Pressure Boundary
Pump casing (component cooling drain tank)	Leakage Boundary (Spatial)
Pump casing (component cooling)	Pressure Boundary
Tank (chemical injection)	Leakage Boundary (Spatial)
Tank (component cooling drain)	Leakage Boundary (Spatial)
Tank (component cooling surge)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-8, Auxiliary Systems - Component Cooling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-9 Demineralized Water - Nuclear Services

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-9, Auxiliary Systems - Demineralized Water - Nuclear Services - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-10 Diesel Generator Services

Component Type	Intended Function(s)
Accumulator (air start positive shutdown)	Pressure Boundary
Air dryer (separator and piping)	Leakage Boundary (Spatial)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Expansion joint	Pressure Boundary
Expansion joint (flange and bellows)	Pressure Boundary
Expansion joint (tube)	Pressure Boundary
Filter housing (fuel oil)	Pressure Boundary, Structural Integrity (Attached)
Filter housing (lube oil)	Pressure Boundary
Filter silencer body	Pressure Boundary
Flame arrestor	Pressure Boundary
Flexible hose	Pressure Boundary
Heat exchanger (intercooler - channel cover)	Pressure Boundary
Heat exchanger (intercooler - channel)	Pressure Boundary
Heat exchanger (intercooler - cover liner)	Pressure Boundary
Heat exchanger (intercooler - shell)	Pressure Boundary
Heat exchanger (intercooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (intercooler - tubesheet)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-10 Diesel Generator Services

Component Type	Intended Function(s)
Heat exchanger (jacket water - channel cover)	Pressure Boundary
Heat exchanger (jacket water - channel)	Pressure Boundary
Heat exchanger (jacket water - cover liner)	Pressure Boundary
Heat exchanger (jacket water - shell)	Pressure Boundary
Heat exchanger (jacket water - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (jacket water - tubesheet)	Pressure Boundary
Heat exchanger (lube oil - channel cover)	Pressure Boundary
Heat exchanger (lube oil - channel)	Pressure Boundary
Heat exchanger (lube oil - cover liner)	Pressure Boundary
Heat exchanger (lube oil - shell)	Pressure Boundary
Heat exchanger (lube oil - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (lube oil - tubesheet)	Pressure Boundary
Heater housing (keep warm)	Pressure Boundary
Heater housing (lube oil)	Pressure Boundary
Manometer	Leakage Boundary (Spatial)
Manometer body	Leakage Boundary (Spatial)
Moisture separator	Leakage Boundary (Spatial)
Muffler	Pressure Boundary
Oil separator	Structural Integrity (Attached)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-10 Diesel Generator Services

Component Type	Intended Function(s)
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (fuel oil transfer)	Pressure Boundary
Pump casing (fuel oil)	Pressure Boundary
Pump casing (intercooler)	Pressure Boundary
Pump casing (jacket water)	Pressure Boundary
Pump casing (keep warm)	Pressure Boundary
Pump casing (lube oil filter)	Pressure Boundary
Pump casing (lube oil)	Pressure Boundary
Pump casing (rocker arm)	Pressure Boundary
Sight glass	Leakage Boundary (Spatial), Pressure Boundary
Sight glass (body)	Leakage Boundary (Spatial), Pressure Boundary
Strainer body	Pressure Boundary
Strainer element	Filtration
Tank (fuel oil day)	Pressure Boundary
Tank (fuel oil storage)	Pressure Boundary
Tank (jacket water head)	Pressure Boundary
Tank (rocker arm lube oil)	Pressure Boundary
Tank (starting air)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-10 Diesel Generator Services

Component Type	Intended Function(s)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-10, Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-11 Domestic Water

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Eyewash - safety shower (stanchion)	Leakage Boundary (Spatial)
Eyewash - safety shower (valve body)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (hot water recirculating)	Leakage Boundary (Spatial)
Tank (hot water)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)
Waterhammer arrestor	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-11, Auxiliary Systems - Domestic Water - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-12 Excess Liquid Waste

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Demineralizer shell	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (excess liquid waste)	Leakage Boundary (Spatial)
Pump casing (radwaste demineralizer booster)	Leakage Boundary (Spatial)
Pump casing (sump)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (decontamination pit collection)	Leakage Boundary (Spatial)
Tank (excess waste hold-up)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-12, Auxiliary Systems - Excess Liquid Waste - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-13 Fire Service

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Exhaust silencer	Pressure Boundary
Flame arrestor	Pressure Boundary
Flexible hose	Pressure Boundary
Heat exchanger coil (carbon dioxide tank)	Pressure Boundary
Hose reel (fitting)	Pressure Boundary
Hydrant	Pressure Boundary
Odorizer	Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Piping, piping components (spectacle flange)	Pressure Boundary
Pump casing (jockey)	Pressure Boundary
Pump casing (motor- and engine-driven column)	Pressure Boundary
Pump casing (motor- and engine-driven)	Pressure Boundary
Sprinkler head	Pressure Boundary
Strainer body	Leakage Boundary (Spatial), Pressure Boundary
Strainer element	Filtration

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-13 Fire Service

Component Type	Intended Function(s)
Strainer element (fire pump suction)	Filtration
Tank (diesel fire pump fuel oil)	Pressure Boundary
Tank (low pressure carbon dioxide)	Pressure Boundary
Tank (retarding chamber)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-13, Auxiliary Systems - Fire Service - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-14 Fuel Handling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Fuel transfer tube	Pressure Boundary, Structural Support
Fuel transfer tube (bellows)	Pressure Boundary
Fuel transfer tube (blind flange)	Pressure Boundary
Fuel transfer tube (penetration sleeve)	Pressure Boundary, Structural Support
Gate seal	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pulsation dampener (upender hydraulic)	Leakage Boundary (Spatial)
Pump casing (upender hydraulic - cylinder)	Leakage Boundary (Spatial)
Pump casing (upender hydraulic - manifold)	Leakage Boundary (Spatial)
Reactor cavity seal ring	Pressure Boundary
Tank (upender hydraulic)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-14, Auxiliary Systems - Fuel Handling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-15 Gaseous Waste Processing

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Compressor housing (waste gas)	Leakage Boundary (Spatial)
Filter housing (waste gas drain)	Leakage Boundary (Spatial)
Flow element (body)	Leakage Boundary (Spatial)
Heat exchanger (compressor - channel)	Pressure Boundary
Heat exchanger (compressor - shell)	Pressure Boundary
Heat exchanger (compressor - tube)	Pressure Boundary
Heat exchanger (compressor - tubesheet)	Pressure Boundary
Heat exchanger (recombiner cooler condenser - channel)	Pressure Boundary
Heat exchanger (recombiner cooler condenser - shell)	Pressure Boundary
Heat exchanger (recombiner cooler condenser - tube)	Pressure Boundary
Heat exchanger (recombiner cooler condenser - tubesheet)	Pressure Boundary
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (decay tank drain)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (compressor separator)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-15 Gaseous Waste Processing

Component Type	Intended Function(s)
Tank (phase separator)	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-15, Auxiliary Systems - Gaseous Waste Processing - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-16 Hydrogen Removal, Post Accident

Component Type	Intended Function(s)
Bolting	Pressure Boundary, Structural Integrity (Attached)
Flow indicator (hydrogen analyzer)	Pressure Boundary
Flow indicator body (hydrogen analyzer)	Pressure Boundary
Heat exchanger (analyzer sample cooling coil)	Heat Transfer, Pressure Boundary
Insulation (safety-related heat traced components)	Thermal insulation
Orifice	Pressure Boundary
Piping, piping components	Pressure Boundary, Structural Integrity (Attached)
Piping, piping components (containment pressure capillary tubing)	Pressure Boundary
Pump casing (hydrogen analyzer sample)	Pressure Boundary
Recombiner (base)	Pressure Boundary
Recombiner (heat duct)	Pressure Boundary
Recombiner (housing)	Pressure Boundary
Separator (hydrogen analyzer)	Pressure Boundary
Valve body	Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-16, Auxiliary Systems - Hydrogen Removal, Post Accident - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-17 Incore Instrumentation

Component Type	Intended Function(s)
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-17, Auxiliary Systems - Incore Instrumentation - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-18 Industrial Cooler

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Flow Element	Leakage Boundary (Spatial)
Heat exchanger (industrial cooling - plate)	Leakage Boundary (Spatial)
Level glass	Leakage Boundary (Spatial)
Level glass (body)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (industrial cooling)	Leakage Boundary (Spatial)
Tank (chemical feed)	Leakage Boundary (Spatial)
Tank (expansion reservoir)	Leakage Boundary (Spatial)
Tank (industrial cooling expansion)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-18, Auxiliary Systems - Industrial Cooler - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-19 Instrument Air

Component Type	Intended Function(s)
Accumulator (PORV backup air)	Pressure Boundary
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Filter silencer body	Structural Integrity (Attached)
Flexible hose	Pressure Boundary
Heat exchanger (reactor building instrument air compressor jacket)	Leakage Boundary (Spatial)
Heat exchanger (reactor building instrument air dryer compressor - jacket)	Leakage Boundary (Spatial)
Heat exchanger (reactor building instrument air dryer condenser - channel)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Strainer body	Leakage Boundary (Spatial)
Tank (portable bottle for local valve operation)	Pressure Boundary
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-19, Auxiliary Systems - Instrument Air - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-20 Leak Detection

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Flow element (body)	Leakage Boundary (Spatial)
Flow indicator	Leakage Boundary (Spatial)
Flow indicator (body)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-20, Auxiliary Systems - Leak Detection - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-21 Liquid Effluents From Nuclear Plant to Penstock

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-21, Auxiliary Systems - Liquid Effluents From Nuclear Plant to Penstock - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-22 Liquid Waste Processing

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Demineralizer shell	Leakage Boundary (Spatial)
Eductor	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (concentrates sample cooler - channel)	Pressure Boundary
Heat exchanger (concentrates sample cooler - shell)	Pressure Boundary
Heat exchanger (concentrates sample cooler - tube and tubesheet)	Pressure Boundary
Heat exchanger (evaporator - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator - shell)	Leakage Boundary (Spatial)
Heat exchanger (evaporator condenser - channel)	Pressure Boundary
Heat exchanger (evaporator condenser - shell)	Pressure Boundary
Heat exchanger (evaporator condenser - tube and tubesheet)	Pressure Boundary
Heat exchanger (evaporator distillate cooler - channel)	Pressure Boundary
Heat exchanger (evaporator distillate cooler - shell)	Pressure Boundary
Heat exchanger (evaporator distillate cooler - tube and tubesheet)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-22 Liquid Waste Processing

Component Type	Intended Function(s)
Heat exchanger (evaporator feed preheater - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator feed preheater - shell)	Leakage Boundary (Spatial)
Heat exchanger (evaporator vent condenser - channel)	Pressure Boundary
Heat exchanger (evaporator vent condenser - shell)	Pressure Boundary
Heat exchanger (evaporator vent condenser - tube and tubesheet)	Pressure Boundary
Heat exchanger (reactor coolant drain tank - channel)	Pressure Boundary
Heat exchanger (reactor coolant drain tank - shell)	Pressure Boundary
Heat exchanger (reactor coolant drain tank - tube)	Pressure Boundary
Heat exchanger (reactor coolant drain tank - tubesheet)	Pressure Boundary
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (chemical drain tank)	Leakage Boundary (Spatial)
Pump casing (evaporator concentrates)	Leakage Boundary (Spatial)
Pump casing (evaporator condensate)	Leakage Boundary (Spatial)
Pump casing (evaporator distillate)	Leakage Boundary (Spatial)
Pump casing (evaporator feed)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-22 Liquid Waste Processing

Component Type	Intended Function(s)
Pump casing (floor drain tank)	Leakage Boundary (Spatial)
Pump casing (laundry and hot shower tank)	Leakage Boundary (Spatial)
Pump casing (reactor coolant drain tank)	Leakage Boundary (Spatial)
Pump casing (spent resin sluice)	Leakage Boundary (Spatial)
Pump casing (waste monitor tank)	Leakage Boundary (Spatial)
Rupture disc	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (chemical drain)	Leakage Boundary (Spatial)
Tank (evaporator condensate)	Leakage Boundary (Spatial)
Tank (floor drain)	Leakage Boundary (Spatial)
Tank (laundry and hot shower)	Leakage Boundary (Spatial)
Tank (reactor coolant drain)	Leakage Boundary (Spatial)
Tank (reagent tank)	Leakage Boundary (Spatial)
Tank (spent resin storage)	Leakage Boundary (Spatial)
Tank (waste holdup)	Leakage Boundary (Spatial)
Tank (waste monitor)	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-22 Liquid Waste Processing

Component Type	Intended Function(s)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-22, Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-23 Material Handling

Component Type	Intended Function(s)
Bolting	Structural Support
Crane rails and retaining clips, girders, beams, plates	Structural Support

The aging management review results for these component types are indicated in Table 3.3.2-23, Auxiliary Systems - Material Handling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-24 Nitrogen Blanketing

Component Type	Intended Function(s)
Bolting	Pressure Boundary, Structural Integrity (Attached)
Piping, piping components	Pressure Boundary, Structural Integrity (Attached)
Valve body	Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-24, Auxiliary Systems - Nitrogen Blanketing - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-25 Nuclear and Miscellaneous Drains

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Level glass	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (sump)	Leakage Boundary (Spatial)
Pump casing (waste drain tank)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (valve stem leakoff drain pot)	Leakage Boundary (Spatial)
Tank (waste drain)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-25, Auxiliary Systems - Nuclear and Miscellaneous Drains - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-26 Nuclear Sampling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Delay coil	Pressure Boundary
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (auxiliary sample cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (sample cooler - shell)	Pressure Boundary
Heat exchanger (sample cooler - tube)	Pressure Boundary
Heat exchanger (sample cooler chiller - channel)	Leakage Boundary (Spatial)
Heat exchanger (water bath)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (flush / dilution)	Leakage Boundary (Spatial)
Pump casing (flush water)	Leakage Boundary (Spatial)
Pump casing (liquid sample circulation)	Leakage Boundary (Spatial)
Pump casing (mannitol)	Leakage Boundary (Spatial)
Pump casing (nitric acid)	Leakage Boundary (Spatial)
Pump casing (sample cooler chiller)	Leakage Boundary (Spatial)
Pump casing (sodium hydroxide)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-26 Nuclear Sampling

Component Type	Intended Function(s)
Pump casing (waste)	Leakage Boundary (Spatial)
Sample flask	Leakage Boundary (Spatial)
Sample sink	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (chemical)	Leakage Boundary (Spatial)
Tank (flush / dilution)	Leakage Boundary (Spatial)
Tank (flush water)	Leakage Boundary (Spatial)
Tank (sample cooler chiller reservoir)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary
Waste sump and panel enclosure	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-26, Auxiliary Systems - Nuclear Sampling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-27 Radiation Monitoring

Component Type	Intended Function(s)
Flow element	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (air sample)	Structural Integrity (Attached)
Radiation monitor	Leakage Boundary (Spatial), Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-27, Auxiliary Systems - Radiation Monitoring - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-28 Radwaste Solidification & Solids Handling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (waste evaporator concentrates transfer)	Leakage Boundary (Spatial)
Sample valve enclosure	Leakage Boundary (Spatial)
Tank (waste blending)	Leakage Boundary (Spatial)
Tank (waste evaporator concentrates)	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-28, Auxiliary Systems - Radwaste Solidification & Solids Handling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-29 Reactor Building Cooling Unit Drains

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Piping, piping components	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-29, Auxiliary Systems - Reactor Building Cooling Unit Drains - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-30 Reactor Building Leak Rate Testing

Component Type	Intended Function(s)
Bolting	Pressure Boundary, Structural Integrity (Attached)
Piping, piping components	Pressure Boundary, Structural Integrity (Attached)
Valve body	Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-30, Auxiliary Systems - Reactor Building Leak Rate Testing - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-31 Reactor Makeup Water Supply

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Flow element	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Heat exchanger (reactor makeup water pump motor - water jacket)	Heat Transfer, Pressure Boundary
Insulation (safety-related heat traced components)	Thermal insulation
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (reactor makeup water)	Pressure Boundary
Tank (reactor makeup water storage)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-31, Auxiliary Systems - Reactor Makeup Water Supply - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-32 Service Water

Component Type	Intended Function(s)
Accumulator	Pressure Boundary
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Calibration column	Leakage Boundary (Spatial)
Calibration column (body)	Leakage Boundary (Spatial)
Flexible hose	Pressure Boundary
Flow element	Pressure Boundary, Restricts Flow
Heat exchanger (service water pump motor bearing cooling coils)	Heat Transfer, Pressure Boundary
Heat exchanger (service water pumphouse cooling coils)	Leakage Boundary (Spatial)
Insulation (steel with internal lining piping)	Thermal insulation
Nozzle (water jet air exhauster)	Leakage Boundary (Spatial)
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Pump casing (chemical injection)	Leakage Boundary (Spatial)
Pump casing (DRPI cooling unit booster)	Leakage Boundary (Spatial)
Pump casing (service water booster)	Pressure Boundary
Pump casing (service water)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-32 Service Water

Component Type	Intended Function(s)
Tank (chemical storage)	Leakage Boundary (Spatial)
Traveling screen element	Filtration
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Valve body (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-32, Auxiliary Systems - Service Water - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-33 Spent Fuel Cooling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Demineralizer shell	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Heat exchanger (spent fuel - channel)	Pressure Boundary
Heat exchanger (spent fuel - shell)	Pressure Boundary
Heat exchanger (spent fuel - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (spent fuel - tubesheet)	Pressure Boundary
Insulation (safety-related heat traced components)	Thermal insulation
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (spent fuel cooling)	Pressure Boundary
Pump casing (spent fuel purification)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-33, Auxiliary Systems - Spent Fuel Cooling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-34 Station Service Air

Component Type	Intended Function(s)
Bolting	Pressure Boundary, Structural Integrity (Attached)
Piping, piping components	Pressure Boundary, Structural Integrity (Attached)
Valve body	Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-34, Auxiliary Systems - Station Service Air - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-35 Thermal Regeneration

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Demineralizer shell	Pressure Boundary
Flow element	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Heat exchanger (chiller condenser and evaporator - channel)	Leakage Boundary (Spatial)
Heat exchanger (chiller lubricating oil - channel)	Leakage Boundary (Spatial)
Heat exchanger (chiller lubricating oil - shell)	Leakage Boundary (Spatial)
Heat exchanger (letdown chiller - channel)	Pressure Boundary
Heat exchanger (letdown chiller - shell)	Pressure Boundary
Heat exchanger (letdown chiller - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (letdown chiller - tubesheet)	Pressure Boundary
Heat exchanger (letdown reheat - channel)	Pressure Boundary
Heat exchanger (letdown reheat - shell)	Pressure Boundary
Heat exchanger (letdown reheat - tube)	Pressure Boundary
Heat exchanger (letdown reheat - tubesheet)	Pressure Boundary
Heat exchanger (moderating - channel)	Pressure Boundary
Heat exchanger (moderating - shell)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-35 Thermal Regeneration

Component Type	Intended Function(s)
Heat exchanger (moderating - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (moderating - tubesheet)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (chiller circulating)	Leakage Boundary (Spatial)
Pump casing (chiller oil)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (chiller surge)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-35, Auxiliary Systems - Thermal Regeneration - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

2.3.4 STEAM AND POWER CONVERSION SYSTEMS

2.3.4.1 Auxiliary Boiler Steam & Feedwater

System Description

The auxiliary boiler steam and feedwater system provides steam to various plant equipment as required during all modes of plant operation. The system will isolate an auxiliary steam high energy pipe rupture to prevent affecting safety-related equipment in the Auxiliary Building.

System Evaluation Boundary

The evaluation boundary for the auxiliary boiler steam and feedwater system components subject to aging management review includes safety-related piping and valves which provide isolation of an auxiliary steam system high energy pipe rupture, as well as nonsafety-related components which are located in buildings containing safety-related components and which distribute auxiliary steam to various steam users.

System Intended Functions

The auxiliary boiler steam and feedwater system performs the following safety-related function: The system isolates an auxiliary steam system high energy pipe rupture to prevent affecting safety-related equipment in the Auxiliary Building. Therefore, the auxiliary boiler steam and feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The auxiliary boiler steam and feedwater system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the auxiliary boiler steam and feedwater system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

The auxiliary boiler steam and feedwater system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the auxiliary boiler steam and feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the auxiliary boiler steam & feedwater system are listed below:

SLR-302-051

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-1, Auxiliary Boiler Steam & Feedwater.

The aging management review results for these component types are indicated in Table 3.4.2-1, Steam and Power Conversion System - Auxiliary Boiler Steam & Feedwater - Aging Management Evaluation.

2.3.4.2 Condensate

System Description

The condensate system is designed to pump condensed turbine exhaust steam from the main condenser hotwell through the low pressure feedwater heaters to maintain deaerator storage tank level for anticipated operating conditions. It also serves as a source of cooling water for the steam packing condenser and steam generator blowdown heat exchanger, and provides sealing water for various vacuum valves and feedwater pump seals.

Except for the condensate storage tank (CST), the condensate system is nonsafety-related. The CST is safety-related since it is the primary inventory source for the emergency feedwater system. Makeup water to the CST is demineralized water, admitted through the condenser and condenser storage subsystem.

System Evaluation Boundary

The evaluation boundary for the condensate system components subject to aging management review consists of only the safety-related condensate storage tank. Piping and components which provide water inventory from the condensate storage tank for plant use are part of the emergency feedwater system.

System Intended Functions

The condensate system performs the following safety-related function: The system provides a water supply via the condensate storage tank to support emergency feedwater system operation. Therefore, the condensate system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The condensate system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the condensate system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the condensate system can be found in the FSAR, Section 10.4.7.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the condensate system are listed below:

SLR-302-085

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-2, Condensate.

The aging management review results for these component types are indicated in Table 3.4.2-2, Steam and Power Conversion System - Condensate - Aging Management Evaluation.

2.3.4.3 Emergency Feedwater

System Description

The emergency feedwater system delivers sufficient feedwater to the steam generators for cooldown after a loss of normal feedwater supply (i.e., when the main feedwater system is not available), and during an Anticipated Transient Without Scram (ATWS) event. The emergency feedwater system operates in conjunction with the main steam dump system, if available, or the main steam power relief valves and safety valves, to remove heat from the steam generators. The emergency feedwater system is also used to supply feedwater to the steam generators during testing, startup, shutdown, and layup operations. During normal plant operation, the system is in a standby condition, with the system controls set for automatic operation.

System Evaluation Boundary

The evaluation boundary for the emergency feedwater system components subject to aging management review includes safety-related piping and components in the flowpath from the condensate storage tank to the steam generators (piping, valves, motor-driven and turbine-driven pumps, turbine lube oil subsystem), as well as the safety-related backup air tanks and associated piping components to the emergency feedwater pump flow control valves. The nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or steam in buildings containing safety-related components are also subject to aging management review. Thermal insulation on outdoor safety-related piping and level instrumentation connected to the condensate storage tank is also subject to aging management review.

System Intended Functions

The emergency feedwater system performs the following safety-related functions: The system provides containment isolation, and provides sufficient feedwater to remove heat from the steam generators. Therefore, the emergency feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The emergency feedwater system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the emergency feedwater system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for pressure boundary integrity, spatial interaction and structural integrity.

The emergency feedwater system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the emergency feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the emergency feedwater system can be found in the FSAR, Section 10.4.9.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the emergency feedwater system are listed below:

SLR-302-085

SLR-302-322

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-3, Emergency Feedwater.

The aging management review results for these component types are indicated in Table 3.4.2-3, Steam and Power Conversion System - Emergency Feedwater - Aging Management Evaluation.

2.3.4.4 Extraction Steam

System Description

The extraction steam system supplies steam for heating the condensate and feedwater, and also, for maintaining the auxiliary boilers in a hot stand-by condition. The mechanical license renewal function of this system is to provide a means of main steam isolation (when used in conjunction with components from various other systems) for a steamline break coincident with failure of a main steam isolation valve.

System Evaluation Boundary

The evaluation boundary for the extraction steam system components subject to aging management review includes nonsafety-related piping and components in the alternate main steam isolation flowpath.

System Intended Functions

The extraction steam system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the extraction steam system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for alternate main steam isolation.

FSAR References

Additional details of the extraction steam system can be found in the FSAR, Section 10.3.2.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the extraction steam system are listed below:

SLR-302-041

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-4, Extraction Steam.

The aging management review results for these component types are indicated in Table 3.4.2-4, Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation.

2.3.4.5 Feedwater

System Description

The feedwater system is designed to pump feedwater from the deaerator storage tank through two stages of high pressure heaters to the steam generators. The operation of this system ensures that the required amount of heated and deaerated water is available to maintain an adequate steam generator water level during normal plant operation and transients.

System Evaluation Boundary

The evaluation boundary for the feedwater system components subject to aging management review includes the safety-related feedwater supply piping and components, containment penetration piping and components, and the backup instrument air supply to the feedwater isolation valves. The nonsafety-related components that interface with the reactor trip instrumentation, that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components are also subject to aging management review. Thermal insulation within containment penetrations is also subject to aging management review.

System Intended Functions

The feedwater system performs the following safety-related functions: The system provides containment integrity isolation, provides reactor trip/ESF actuation signals based on feedwater flow, and maintains secondary system pressure boundary integrity. Therefore, the feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The feedwater system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the feedwater system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for reactor trip instrumentation interface, and for spatial interaction and structural integrity.

The feedwater system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Environmental Qualification (10 CFR 50.49). Therefore, the feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the feedwater system can be found in the FSAR, Section 10.4.7.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the feedwater system are listed below:

SLR-302-083

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-5, Feedwater.

The aging management review results for these component types are indicated in Table 3.4.2-5, Steam and Power Conversion System - Feedwater - Aging Management Evaluation.

2.3.4.6 Gland Sealing Steam

System Description

The gland sealing steam system is designed to provide steam to the main turbine and feedwater pump turbine shaft seals in order to prevent air leakage into and/or steam leakage out of the turbine casings. Sealing steam is normally supplied to the gland sealing steam system from the main steam system under all load conditions, but may be provided by the auxiliary boiler through the auxiliary steam system. The mechanical license renewal function of this system is to provide a means of main steam isolation (when used in conjunction with components from various other systems) for a steamline break coincident with failure of a main steam isolation valve.

System Evaluation Boundary

The evaluation boundary for the gland sealing steam system components subject to aging management review includes nonsafety-related piping and components in the alternate main steam isolation flowpath.

System Intended Functions

The gland sealing steam system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the gland sealing steam system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for alternate main steam isolation.

FSAR References

Additional details of the gland sealing steam system can be found in the FSAR, Section 10.4.3, 10.3.2.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the gland sealing steam system are listed below:

SLR-302-141

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-6, Gland Sealing Steam.

The aging management review results for these component types are indicated in Table 3.4.2-6, Steam and Power Conversion System - Gland Sealing Steam - Aging Management Evaluation.

2.3.4.7 Main Steam

System Description

The main steam system conveys saturated steam from the three steam generators to the turbine-generator. Main steam is also supplied, through branch lines, to the following: (a) feedwater pump drive turbines, (b) emergency feedwater pump drive turbine, (c) moisture separator reheaters, (d) auxiliary steam system, (e) deaerating feedwater heater, and (f) steam dumps to the condenser and atmosphere.

System Evaluation Boundary

The evaluation boundary for the main steam system components subject to aging management review includes safety-related piping and components in the flowpath from the steam generators to the containment isolation valves to the emergency feedwater pump drive turbine, as well as the backup instrument air supply to the emergency feedwater pump turbine steam supply valve. The nonsafety-related piping and components in the alternate main steam isolation flowpath, as well as nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or steam in buildings containing safety-related components, are also subject to aging management review. Thermal insulation within containment penetrations is also subject to aging management review.

System Intended Functions

The main steam system performs the following safety-related functions: The system provides steam to the turbine driven emergency feedwater turbine during accident conditions, provides a steam relief path for heat removal and steam generator depressurization, and provides reactor trip/ESF actuation signals based on applicable plant conditions. The system also provides containment isolation. Therefore, the main steam system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The main steam system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the main steam system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for alternate main steam isolation and for spatial interaction and structural integrity.

The main steam system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the main steam system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the main steam system can be found in the FSAR, Section 10.3, 10.3.2.3, 5.5.7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the main steam system are listed below:

SLR-302-011

SLR-302-012

SLR-302-014

SLR-302-121

SLR-302-122

SLR-302-123

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-7, Main Steam.

The aging management review results for these component types are indicated in Table 3.4.2-7, Steam and Power Conversion System - Main Steam - Aging Management Evaluation.

2.3.4.8 Main Steam Dump

System Description

The main steam system is capable of following a large turbine-generator load reduction without reactor trip, through actuation of the main steam dump system. The main steam dump system bypasses main steam to the main condenser and/or to the atmosphere. Steam dump valves permit unit operation at turbine loads lower than the minimum power setting (15% reactor power) of the Nuclear Steam Supply System (NSSS) automatic control.

The mechanical license renewal function of this system is to provide a means of main steam isolation (when used in conjunction with components from various other systems) for a steamline break coincident with failure of a main steam isolation valve.

System Evaluation Boundary

The evaluation boundary for the main steam dump system components subject to aging management review includes nonsafety-related piping and components in the alternate main steam isolation flowpath, as well as nonsafety-related piping and piping components that retain water in buildings containing safety-related components.

System Intended Functions

The main steam dump system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the main steam dump system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for alternate main steam isolation and for spatial interaction.

The main steam dump system is relied upon for compliance with regulations Environmental Qualification (10 CFR 50.49). Therefore, the main steam dump system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the main steam dump system can be found in the FSAR, Section 10.4.4, 10.3.2.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the main steam dump system are listed below:

SLR-302-031

SLR-302-121

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-8, Main Steam Dump.

The aging management review results for these component types are indicated in Table 3.4.2-8, Steam and Power Conversion System - Main Steam Dump - Aging Management Evaluation.

2.3.4.9 Nuclear Blowdown Processing

System Description

The nuclear blowdown processing system is a nonsafety-related system that processes cooled steam generator blowdown fluid and returns decontaminated water to the secondary cycle.

System Evaluation Boundary

The evaluation boundary for the nuclear blowdown processing system components subject to aging management review includes nonsafety-related components that retain water in buildings containing safety-related components.

System Intended Functions

The nuclear blowdown processing system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the nuclear blowdown processing system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

FSAR References

Additional details of the nuclear blowdown processing system can be found in the FSAR, Section 10.4.8.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the nuclear blowdown processing system are listed below:

SLR-302-782

SLR-302-783

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-9, Nuclear Blowdown Processing.

The aging management review results for these component types are indicated in Table 3.4.2-9, Steam and Power Conversion System - Nuclear Blowdown Processing - Aging Management Evaluation.

2.3.4.10 Steam Generator Blowdown

System Description

The steam generator blowdown system continuously purges the steam generators of concentrated impurities, thereby maintaining secondary side steam generator water chemistry. This system is nonsafety-related except for the portion inside the Reactor Building, up to and including the containment isolation valves.

System Evaluation Boundary

The evaluation boundary for the steam generator blowdown system components subject to aging management review includes safety-related piping and valves from the steam generators to the containment isolation valves, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components. Thermal insulation within containment penetrations is also subject to aging management review.

System Intended Functions

The steam generator blowdown system performs the following safety-related functions: The system provides containment isolation and maintains secondary system pressure boundary integrity. Therefore, the steam generator blowdown system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The steam generator blowdown system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the steam generator blowdown system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The steam generator blowdown system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the steam generator blowdown system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the steam generator blowdown system can be found in the FSAR, Section 10.4.8, Table 6.2-53.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the steam generator blowdown system are listed below:

SLR-302-781

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-10, Steam Generator Blowdown.

The aging management review results for these component types are indicated in Table 3.4.2-10, Steam and Power Conversion System - Steam Generator Blowdown - Aging Management Evaluation.

2.3.4.11 Turbine Cycle Chemical Feed

System Description

The turbine cycle chemical feed system is a nonsafety-related system that provides chemical treatment for the condensate and feedwater systems.

System Evaluation Boundary

The evaluation boundary for the turbine cycle chemical feed system components subject to aging management review includes nonsafety-related components that retain water in buildings containing safety-related components.

System Intended Functions

The turbine cycle chemical feed system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the turbine cycle chemical feed system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

FSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the turbine cycle chemical feed system are listed below:

SLR-302-171

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-11, Turbine Cycle Chemical Feed.

The aging management review results for these component types are indicated in Table 3.4.2-11, Steam and Power Conversion System - Turbine Cycle Chemical Feed - Aging Management Evaluation.

2.3.4.12 Turbine Cycle Sampling

System Description

The turbine cycle sampling system provides sampling of secondary system fluids from locations such as the main condenser hotwell, deaerator, feedwater booster pumps, high pressure heater drains, emergency feedwater pumps, and main steam system. Portions of the system provide a means of main steam isolation (when used in conjunction with components from various other systems) for a steamline break coincident with failure of a main steam isolation valve.

System Evaluation Boundary

The evaluation boundary for the turbine cycle sampling system components subject to aging management review includes nonsafety-related piping and components in the alternate main steam isolation flowpath, and nonsafety-related components that retain water in buildings containing safety-related components

System Intended Functions

The turbine cycle sampling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the turbine cycle sampling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for alternate main steam isolation and spatial interaction.

FSAR References

Additional details of the turbine cycle sampling system can be found in the FSAR, Section 10.3.5, 10.3.2.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the turbine cycle sampling system are listed below:

SLR-302-181

SLR-302-182

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-12, Turbine Cycle Sampling.

The aging management review results for these component types are indicated in Table 3.4.2-12, Steam and Power Conversion System - Turbine Cycle Sampling - Aging Management Evaluation.

2.3.4.13 Turbine Electro-Hydraulic

System Description

The turbine electro-hydraulic control system actuates and controls the turbine steam inlet valves. The turbine electro-hydraulic control system establishes the desired turbine steady-state load. This system implements turbine trips that have license renewal functions of ATWS mitigation and main steam isolation (when used in conjunction with components from various other systems) for a steamline break coincident with failure of a main steam isolation valve.

System Evaluation Boundary

There are no passive mechanical components whose integrity is required for the turbine electro-hydraulic control system to perform its intended function; therefore, there are no components subject to aging management review.

System Intended Functions

The turbine electro-hydraulic control system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the turbine electro-hydraulic control system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for alternate main steam isolation.

The turbine electro-hydraulic control system is relied upon for compliance with regulations for Anticipated Transients Without Scram (10 CFR 50.62). Therefore, the turbine electro-hydraulic control system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the turbine electro-hydraulic system can be found in the FSAR, Section 10.2.2.2, 10.3.2.3.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the turbine electro-hydraulic system.

Components Subject to Aging Management Review

None

Screening Results Tables: Steam and Power Conversion Systems

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-1 Auxiliary Boiler Steam & Feedwater

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (condensate return - shell)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (condensate return)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Steam trap body	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (condensate return)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-1, Steam and Power Conversion System - Auxiliary Boiler Steam & Feedwater - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-2 Condensate

Component Type	Intended Function(s)
Tank (condensate storage)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-2, Steam and Power Conversion System - Condensate - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-3 Emergency Feedwater

Component Type	Intended Function(s)
Accumulator	Pressure Boundary
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Pressure Boundary, Structural Integrity (Attached)
Flow element	Pressure Boundary, Restricts Flow
Heat exchanger (EF pump turbine lube oil - channel)	Pressure Boundary
Heat exchanger (EF pump turbine lube oil - shell)	Pressure Boundary
Heat exchanger (EF pump turbine lube oil - tube sheet)	Pressure Boundary
Heat exchanger (EF pump turbine lube oil - tube)	Heat Transfer, Pressure Boundary
Insulation (safety-related heat traced components)	Thermal insulation
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump Casing (motor driven emergency feedwater)	Pressure Boundary
Pump Casing (turbine driven emergency feedwater)	Pressure Boundary
Pump casing (turbine lube oil)	Pressure Boundary
Tank (turbine lube oil reservoir)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-3 Emergency Feedwater

Component Type	Intended Function(s)
Turbine casing (emergency feedwater pump)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.4.2-3, Steam and Power Conversion System - Emergency Feedwater - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-4 Extraction Steam

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Piping, piping components	Pressure Boundary
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-4, Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-5 Feedwater

Component Type	Intended Function(s)
Accumulator	Pressure Boundary
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Flow element	Leakage Boundary (Spatial), Restricts Flow
Insulation (containment penetration)	Thermal insulation
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-5, Steam and Power Conversion System - Feedwater - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-6 Gland Sealing Steam

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Piping, piping components	Pressure Boundary
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-6, Steam and Power Conversion System - Gland Sealing Steam - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-7 Main Steam

Component Type	Intended Function(s)
Accumulator	Pressure Boundary
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Diffuser	Leakage Boundary (Spatial)
Drain trap	Pressure Boundary
Insulation (containment penetration)	Thermal insulation
Moisture collector	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Strainer body	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.4.2-7, Steam and Power Conversion System - Main Steam - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-8 Main Steam Dump

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Drain trap	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Strainer body	Pressure Boundary
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-8, Steam and Power Conversion System - Main Steam Dump - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-9 Nuclear Blowdown Processing

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Demineralizer shell (polishing)	Leakage Boundary (Spatial)
Demineralizer shell (primary)	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (holdup tank transfer pump motor cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (NB monitor tank transfer pump motor cooler - shell)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (holdup tank transfer)	Leakage Boundary (Spatial)
Pump casing (NB monitor tank transfer)	Leakage Boundary (Spatial)
Pump casing (spent resin sluicing)	Leakage Boundary (Spatial)
Resin trap body	Leakage Boundary (Spatial)
Tank (holdup)	Leakage Boundary (Spatial)
Tank (NB monitor)	Leakage Boundary (Spatial)
Tank (spent resin storage)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-9, Steam and Power Conversion System - Nuclear Blowdown Processing - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-10 Steam Generator Blowdown

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing (steam generator wet layup)	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Flow indicator (body)	Leakage Boundary (Spatial)
Insulation (containment penetration)	Thermal insulation
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (steam generator wet layup)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-10, Steam and Power Conversion System - Steam Generator Blowdown - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-11 Turbine Cycle Chemical Feed

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Level glass	Leakage Boundary (Spatial)
Level glass (body)	Leakage Boundary (Spatial)
Oil trap	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (condensate alternate injection)	Leakage Boundary (Spatial)
Pump casing (condensate ammonia injection)	Leakage Boundary (Spatial)
Pump casing (condensate hydrazine injection)	Leakage Boundary (Spatial)
Pump casing (steam generator ammonia injection)	Leakage Boundary (Spatial)
Pump casing (steam generator hydrazine injection)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (condensate ammonia injection)	Leakage Boundary (Spatial)
Tank (condensate hydrazine injection)	Leakage Boundary (Spatial)
Tank (steam generator standby ammonia injection)	Leakage Boundary (Spatial)
Tank (steam generator standby hydrazine injection)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

The aging management review results for these component types are indicated in Table 3.4.2-11, Steam and Power Conversion System - Turbine Cycle Chemical Feed - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-12   Turbine Cycle Sampling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (sample recovery tank transfer)	Leakage Boundary (Spatial)
Sample element	Leakage Boundary (Spatial)
Tank (sample recovery)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-12, Steam and Power Conversion System - Turbine Cycle Sampling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

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2.4 SCOPING AND SCREENING RESULTS: STRUCTURES

2.4.1 CONTAINMENTS, STRUCTURES, AND COMPONENT SUPPORTS

2.4.1.1 Reactor Building

System Description

The Reactor Building (Containment) is a post tensioned, reinforced concrete structure with an integral steel liner. The Reactor Building consists of a cylindrical wall, a shallow dome roof, and a circular foundation mat with a depressed incore instrumentation pit under the reactor vessel. The foundation consists of a concrete structural mat, which is conventionally reinforced top and bottom. The foundation mat is supported by fill concrete that extends down to competent rock. A circumferential tunnel or gallery is provided under the perimeter of the foundation mat to allow access to the bottom anchorage of the cylindrical wall vertical tendons.

A retaining wall, extending approximately one quarter (1/4) of the way around the Reactor Building, separates the below grade portions of the Reactor Building wall from the subgrade and groundwater. Adjacent buildings surround the remaining three-quarters (3/4) of the Reactor Building.

The cylindrical wall and the shallow dome roof are joined at a ring girder. The cylindrical wall and the dome roof are post tensioned by ungrouted tendons. The cylindrical wall employs a three-buttress, 240-degree hoop tendon concept, with 115 vertical tendons and 150 hoop tendons. The dome roof contains a total of 99 tendons arranged in a three-way system with 33 tendons per band.

The Reactor Building is lined on the inside face with a carbon steel plate liner that forms an essentially leak-tight membrane. The bottom of the liner consists of flat floor liner plates welded to anchors that are embedded in the mat concrete. A concrete slab placed on top of the foundation mat liner serves as the basement floor. The liner plate extends downward into the foundation mat to line the incore instrumentation pit, the Reactor Building sump, the incore instrumentation pit sump, the residual heat removal sumps, and the Reactor Building spray sumps. The incore instrumentation pit walls are lined with carbon steel plates, while the pit bottom and the walls of the incore instrumentation tunnel are lined with stainless steel plates. The residual heat removal sump, Reactor Building sump, and Reactor Building spray sump floors and sidewalls are lined with stainless steel plate.

Small diameter circular overlay plates are welded to the liner plate to support piping, ducts, conduit, and electric cable trays. Studs or angle anchors are provided on the liner behind the attachment plates to transfer loads on the pads into the concrete shell.

Reactor Building penetrations are anchored to the concrete Reactor Building wall or foundation mat so that loads are transferred from the penetrations to the concrete. Piping penetrations consist of a sleeve around the outside of the piping. The piping is joined to the sleeve inside the Reactor Building by an attachment plate. Outside the Reactor Building, piping is attached to the sleeve by an attachment plate or by a bellows assembly.

Electrical penetration sleeves are provided to accommodate electrical and instrumentation cables that pass through the Reactor Building wall. The electrical leads are installed in the penetration assemblies that are bolted to the electrical penetration sleeve.

Spare penetrations consist of sleeves passing through the Reactor Building wall with the liner reinforced around the sleeve. The ends of the sleeve are sealed with butt-welded pipe caps or with bolted removable blank flanges and gaskets.

A fuel transfer tube penetrates the Reactor Building connecting the refueling canal in the Reactor Building and the fuel transfer canal in the Fuel Handling Building. This penetration consists of a pipe installed inside a sleeve.

Access and egress from the Reactor Building are through a personnel access air lock. In addition, a smaller personnel escape air lock is provided for emergency use. Each of the personnel airlocks are provided with two doors, one on the inside and one on the outside. Each door is sealed with double O-rings.

An equipment hatch, equipped with an inside-mounted hatch cover, is also provided for access to the Reactor Building. A concrete shield located outside the Reactor Building acts as a missile and biological shield. The hatch cover is sealed with double O-rings.

The internal structures of the Reactor Building consist of the following:

- Primary shield wall surrounding and supporting the reactor vessel.
- Secondary shield walls, surrounding and laterally supporting each steam generator and the pressurizer.
- Refueling cavity and fuel transfer canal.
- Mezzanine floor and operating floor, both consisting of concrete slabs supported by structural steel framing.
- Concrete basement slab supported by the structural foundation mat.

The primary shield wall is a reinforced concrete wall surrounding and supporting the reactor vessel. The lower portion of the wall, below the base slab, is a cylindrical section surrounded by structural foundation mat concrete. The Reactor Building foundation mat provides vertical support of the primary shield wall.

The secondary shield walls form three compartments that are located adjacent to and are connected with the primary shield wall. These compartments form enclosures for Reactor Coolant System equipment. The function of these enclosures is to protect the Reactor Building from the effects of a postulated pipe break, provide biological shielding, and provide lateral support for Reactor Coolant System equipment. The pressurizer is enclosed in a separate compartment.

The refueling cavity/fuel transfer canal is located above and adjacent to the reactor vessel and is a stainless steel lined reinforced concrete structure. The walls of the refueling cavity/fuel transfer canal form part of the secondary shield wall system.

The operating floor slab and the mezzanine floor slab are supported by a structural steel framing system and by the secondary shield walls. The inner edge of these reinforced concrete slabs are keyed and doweled into the secondary shield walls. The outer edge stops short of the Reactor Building liner to provide separation from the exterior Reactor Building cylindrical wall.

The structural steel framing system consists of radially oriented girders supported on the inboard ends by concrete corbels or steel brackets attached to the secondary shield wall. Steel columns support the outboard ends of the girders, with base plates supported on piers cast in the basement floor slab. Perimeter girders between the columns support the outboard portion of the operating and mezzanine floor slabs. Steel beams frame between the girders to support the floor slabs.

The Reactor Building foundation mat supports a concrete basement slab, which supports and anchors all the internal structures and equipment. The Reactor Building base mat liner is not penetrated for anchorage of any internal structure or equipment.

Service Level I coatings are used in areas inside the Reactor Building (e.g., steel liner, penetrations, and concrete walls and floors).

System Evaluation Boundary

The evaluation boundary for the Reactor Building subject to aging management review includes bolting; concrete elements associated with beams, columns, walls, slabs, curbs, foundations, pads, jet impingement barriers, missile barriers, tendon access gallery, dome, ring girder and buttresses; Containment liner which includes liner plates, liner leak chase channels, liner anchors, and integral attachments; equipment hatch, personnel air lock, emergency escape lock, and accessories (hinges, pins, closure mechanisms); moisture barriers; penetrations (electrical); penetrations (mechanical); refueling cavity/fuel transfer canal liner; seals and gaskets which include O-rings and other elastomer materials that are part of the Containment pressure boundary; Service Level I coatings; steel elements associated with beams, columns, baseplates, bracing, stairs, platforms, grating, decking, ladders, missile barriers, and embedded steel; sump liners; tendon anchorage components, and tendons. The retaining wall that separates the below grade portions of the Reactor Building wall from the subgrade does not perform an intended function for subsequent license renewal and is, therefore, not in-scope.

For mechanical penetrations, penetration piping components and isolation valves are evaluated with the mechanical host system. Electrical penetration assemblies are within the scope of the EQ program. The portions of the electrical penetrations that form part of the Containment pressure boundary are included within the Reactor Building evaluation boundary. The fuel transfer tube assembly and blind flange, and reactor cavity seal assembly are evaluated with the fuel handling system. The sump screen assemblies associated with the Reactor Building sumps are evaluated with the mechanical host system. The isolation valve chambers, guard pipes, and bellows associated with the Reactor Building Spray and RHR systems that are located in the Auxiliary Building, are evaluated with the Auxiliary Building. The reactor vessel supports are evaluated with NSSS Supports.

System Intended Functions

The Reactor Building performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Reactor Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Reactor Building provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Reactor Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Reactor Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the Reactor Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Reactor Building can be found in the FSAR, Sections 3.1, 3.2, 3.8, and 6.2; Tables 3.8-1 through 3.8-5; Figures 3.8-1 through 3.8-22, and Figures 3.8-39 through 3.8-51.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Reactor Building.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-1, Reactor Building.

The aging management review results for these component types are indicated in Table 3.5.2-1, Containment Structure - Aging Management Evaluation.

2.4.1.2 Auxiliary Building

System Description

The Auxiliary Building is a reinforced concrete shear wall (box type) structure. The floors are reinforced concrete supported on concrete walls. The foundation system for the Auxiliary Building consists of a structural reinforced concrete mat supported by fill concrete extending down to competent rock.

The Seismic Category I portion of the Auxiliary Building has a roof and exterior walls that are reinforced concrete designed to prevent damage to safety-related equipment areas from tornado missiles and tornado missile effects. A Non-Seismic Category 1 structure of steel frame, metal siding, and metal roof deck is located on the roof of the Auxiliary Building. Built-up roofing or roof membranes exist over sections of the Auxiliary Building roof.

Piping and isolation valves connecting to the Reactor Building recirculation sumps associated with reactor building spray and residual heat removal are located in the Auxiliary Building. This piping is enclosed in guard pipes. The guard pipes connect to protective chambers that completely surrounds the isolation valves. The guard pipes and isolation valve chambers are considered to be extensions of the Containment pressure boundary, and are evaluated with the Auxiliary Building.

The southwestern portion of the Auxiliary Building supports the refueling water storage tank, reactor make-up water storage tank, and the sodium hydroxide storage tank. These tanks are secured to a portion of the concrete roof with anchor bolts and are exposed to the outside environment. Caulking is used at the tank external surfaces and concrete interface for the refueling water storage tank and the reactor make-up water storage tank.

The southeastern portion of the Auxiliary Building is designated the west penetration access area (WPAA), which houses the containment personnel airlock. The WPAA utilizes structural steel framing to support the floor slabs up to the elevation of the roof.

System Evaluation Boundary

The evaluation boundary for the Auxiliary Building includes bellows; bolting; concrete elements associated with beams, columns, walls, slabs, foundation, duct banks, missile shields, knockdown walls, and pads; caulking and sealants; Containment liner; doors; masonry block walls; roofing membrane; and steel elements associated with beams, columns, ladders, grating, siding, blow-off panels, stairs, missile shields, baseplates, and embedded steel.

The refueling water storage tank is evaluated with the refueling water system. The reactor make-up water storage tank is evaluated with the reactor makeup water supply system.

System Intended Functions

The Auxiliary Building performs the following safety-related functions: The structure provides structural support, shelter, and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Auxiliary Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Auxiliary Building provides structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Auxiliary Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Auxiliary Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the Auxiliary Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Auxiliary Building can be found in the FSAR, Sections 3.8.4.1.2 and 3.8.5.1.2; Figures 3.8-53 and 3.8-54; and Table 3.2-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Auxiliary Building.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-2, Auxiliary Building.

The aging management review results for these component types are indicated in Table 3.5.2-2, Structures and Component Supports - Auxiliary Building - Aging Management Evaluation.

2.4.1.3 Auxiliary Service Building

System Description

The Auxiliary Service Building is a two-story steel framed structure founded on reinforced concrete footings and a mat foundation. The concrete footings and mat foundation for the Auxiliary Service Building are supported on compacted subgrade, and the structure is enclosed with metal siding and masonry block walls. The roof consists of metal decking covered with a built-up roof. The intermediate floor is constructed of reinforced concrete and is supported by steel framing.

System Evaluation Boundary

The evaluation boundary for the Auxiliary Service Building includes bolting; concrete elements associated with beams, walls, slabs, foundation, and pads; doors; masonry block walls; roofing membrane; and steel elements associated with beams, columns, siding, decking, baseplates, and embedded steel.

System Intended Functions

The Auxiliary Service Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). The Auxiliary Service Building is not required for compliance with NFPA-805, but provides support and shelter for in-scope fire suppression piping. Therefore, the Auxiliary Service Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Auxiliary Service Building can be found in the FSAR, Section 2.3.3.2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Auxiliary Service Building.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-3, Auxiliary Service Building.

The aging management review results for these component types are indicated in Table 3.5.2-3, Structures and Component Supports - Auxiliary Service Building - Aging Management Evaluation.

2.4.1.4 Circulating Water Intake Structure

System Description

The Circulating Water Intake Structure is a reinforced concrete (box-type) and is located on the south side of Monticello Reservoir, north of the main group of plant buildings. The Circulating Water Intake Structure is a non-safety structure that houses equipment that provides circulating water to support plant operations.

Located on top or deck of the reinforced concrete Circulating Water Intake Structure are two masonry block buildings, which house other non-safety systems. One concrete block building is the Screen Wash Pumphouse, which houses the screen wash pumps. The second concrete block building is the Fire Service Pumphouse, which houses the diesel-driven fire service pump, the motor-driven fire service pump, and other plant service pumps. The Screen Wash Pumphouse does not perform an intended function for subsequent license renewal and is, therefore, not in-scope.

Fire Service Pumphouse is a concrete block building, which houses equipment that do perform an intended function for subsequent license renewal and is, therefore, in-scope. Concrete blocks are used to form the exterior and interior walls of the building and support steel framing members. The roof of the Fire Service Pumphouse consists of metal decking covered with a built-up roof.

A reinforced concrete slab located on the east side of the Fire Service Pumphouse and founded upon the Circulating Water Intake Structure is also included in the evaluation of the Circulating Water Intake Structure. This reinforced concrete slab is the foundation for the diesel engine driven fire service pump fuel oil tank.

System Evaluation Boundary

The evaluation boundary for the Circulating Water Intake Structure includes aluminum elements associated with louvers and screens; bolting; concrete elements associated with beams, columns, walls, slabs, foundation, and pads; doors; masonry block walls; roofing membrane; and steel elements associated with beams, columns, grating, baseplates, and embedded steel.

The Screen Wash Pumphouse does not perform an intended function for subsequent license renewal and is, therefore, not in-scope.

System Intended Functions

The Circulating Water Intake Structure is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Circulating Water Intake Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Circulating Water Intake Structure can be found in the FSAR, Sections 1.2.3.9.7 and 2.4.8; Figure 1.2-23; and Table 3.2-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Circulating Water Intake Structure.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-4, Circulating Water Intake Structure.

The aging management review results for these component types are indicated in Table 3.5.2-4, Structures and Component Supports - Circulating Water Intake Structure - Aging Management Evaluation.

2.4.1.5 Component Supports

System Description

Component Supports for mechanical and electrical components are an integral part of plant systems. The majority of these supports are not uniquely identified; however, Component Supports exhibit similar characteristics such as design, materials of construction, environments, and aging. Therefore, Component Supports for mechanical and electrical components are evaluated as plant structural commodities.

The commodity evaluation applies to the supports for mechanical and electrical components within the buildings and structures that are within the scope of subsequent license renewal. The supports subject to aging management review that are addressed in this section include supports and anchorage for the following:

- ASME Class 2 and Class 3 piping and components
- Cable trays, conduit, cable bus enclosure assemblies, HVAC ducts, tube tracks, instrument tubing, and non-ASME Code piping and components
- Racks, panels, cabinets, and enclosures for electrical equipment and instrumentation
- Emergency diesel generator and HVAC system components, and other miscellaneous mechanical equipment
- Platforms, pipe whip restraints, jet impingement shields, masonry walls, and other miscellaneous structures

In addition, cable trays, conduits, instrument racks, and structural frames are addressed in this section.

Some piping and equipment are restrained or supported to prevent interaction with safety-related SSCs. This piping and equipment may not be included within the scope of subsequent license renewal, but the structural supports for the piping and equipment are included in-scope and are subject to aging management review.

System Evaluation Boundary

The evaluation boundary for Component Supports includes supports for mechanical and electrical components that are within the scope of subsequent license renewal, and for mechanical and electrical components that are not within the scope of subsequent license renewal, but are located such that their failure could adversely impact the performance of a safety-related SSC intended function. Component Supports include aluminum elements associated with support members, cable trays, and conduits; bolting; grout; sliding surfaces; spring hangers; guides; stops; stainless steel elements associated with support members, cable trays, and conduits; steel elements associated with support members, bearing plates, baseplates, connections, cable trays, conduits, instrument racks, and structural frames; and vibration isolation elements.

The evaluation boundary for Component Supports lies between the equipment or component being supported and the building supporting structure (concrete or structural steel). The portions of steel anchors embedded in concrete are evaluated with the building structure. Integral attachments and welds to pressure retaining components are addressed with the specific component in other sections.

Component Supports for ASME Class 1 piping and components, including NSSS equipment, are evaluated with NSSS Supports. Steel elements, such as beams, columns, baseplates, bracing, stairs, platforms, grating, decking, and ladders are evaluated with the applicable buildings and structures that are within the scope of subsequent license renewal.

System Intended Functions

Component Supports perform the following safety-related functions: Component Supports provide structural support, shelter, and protection for safety-related SSCs. Therefore, Component Supports are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Component Supports provide structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Component Supports are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Component Supports are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, Component Supports are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Component Supports can be found in the FSAR, Sections 3.9.2.8, 3.10, and 8.3; Figure 3.9-2; and Tables 3.9-9, 3.10-1, and 3.10-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the component supports.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-5, Component Supports.

The aging management review results for these component types are indicated in Table 3.5.2-5, Structures and Component Supports - Component Supports - Aging Management Evaluation.

2.4.1.6 Control Building

System Description

The Control Building is a steel framed structure with concrete floor slabs, concrete exterior shear walls, and a concrete roof. The Control Building has four main floor levels, and houses the control room. The foundation system for the Control Building consists of a reinforced concrete mat supported by fill concrete extending down to competent rock.

The Control Building is a Seismic Category I structure. The roof and exterior walls are of reinforced concrete designed to prevent damage to safety-related equipment from tornado generated missiles. Built-up roofing exists over sections of the Control Building.

System Evaluation Boundary

The evaluation boundary for the Control Building includes bolting; concrete elements associated with beams, columns, walls, slabs, foundation, duct banks, knockdown walls, missile shields, and pads; doors; roofing membrane; and steel elements associated with beams, columns, ladders, grating, stairs, missile shields, baseplates, and embedded steel.

System Intended Functions

The Control Building performs the following safety-related functions: The structure provides structural support, shelter, and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Control Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Control Building provides structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Control Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Control Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the Control Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Control Building can be found in the FSAR, Sections 3.8.4.1.5 and 3.8.5.1.4; Figures 3.8-55 and 3.8-57; and Table 3.2-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Control Building.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-6, Control Building.

The aging management review results for these component types are indicated in Table 3.5.2-6, Structures and Component Supports - Control Building - Aging Management Evaluation.

2.4.1.7 Diesel Generator Building

System Description

The Diesel Generator Building is a reinforced concrete shear wall (box type) structure containing three main floor levels above the foundation mat, and a roof. Built-up roofing exists over sections of the building. The primary function of the Diesel Generator Building is to house the diesel generators that are needed to supply emergency onsite power in the event that offsite power is lost.

The foundation system for the Diesel Generator Building consists of a reinforced concrete slab and grade beam system that is supported by reinforced concrete caissons drilled into competent rock. The foundations for the diesel generators extend from the operating floor level down to the basement floor mat.

The Diesel Generator Building is a Seismic Category I structure. The walls and roof of the Diesel Generator Building are designed to prevent damage to safety-related equipment from tornado missiles and their effects.

System Evaluation Boundary

The evaluation boundary for the Diesel Generator Building includes aluminum elements associated with louvers and screens; bolting; concrete elements associated with beams, columns, walls, slabs, foundation, caissons, duct banks, knockdown walls, missile shields, and pads; doors; roofing membrane; and steel elements associated with beams, columns, ladders, grating, stairs, missile shields, baseplates, and embedded steel.

System Intended Functions

The Diesel Generator Building performs the following safety-related functions: The structure provides structural support, shelter, and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Diesel Generator Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Diesel Generator Building provides structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Diesel Generator Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Diesel Generator Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Diesel Generator Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Diesel Generator Building can be found in the FSAR, Sections 3.8.4.1.4 and 3.8.5.1.6; Figure 3.8-56; and Table 3.2-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Diesel Generator Building.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-7, Diesel Generator Building.

The aging management review results for these component types are indicated in Table 3.5.2-7, Structures and Component Supports - Diesel Generator Building - Aging Management Evaluation.

2.4.1.8 Duct Banks

System Description

Duct Banks are underground reinforced concrete structures used for the routing of electrical cables between plant structures. Duct Banks are configured of multiple conduits in an excavated trench that are encased in concrete and then backfilled.

Included with the evaluation of Duct Banks are reinforced concrete cable trenches. Cable trenches may be above ground or partially underground, but cable trenches have removable concrete covers to allow for access.

System Evaluation Boundary

The evaluation boundary for the Duct Banks includes concrete elements associated with duct banks and cable trenches. For duct banks and cable trenches, the evaluation boundaries terminate at the point that these structures interface with or enter separate structures (e.g., building or manhole).

System Intended Functions

Duct Banks perform the following safety-related functions: Duct Banks provide structural support and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, Duct Banks are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Duct Banks are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Duct Banks are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Duct Banks can be found in the FSAR, Sections 8.3.1.4.1 and 18.2.32; and Figures 8.3-2a through 8.3-2g.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the duct banks.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-8, Duct Banks.

The aging management review results for these component types are indicated in Table 3.5.2-8, Structures and Component Supports - Duct Banks - Aging Management Evaluation.

2.4.1.9 Earthen Embankments

System Description

The following Earthen Embankments are subject to aging management review:

Service Water Pond Dams and West Embankment

Four earthen embankments – three dams (North Dam, South Dam, and East Dam) and the West Embankment – form the Service Water Pond. The Service Water Pond is a Seismic Category I impoundment that provides water for the service water system under normal and emergency conditions, and is the ultimate heat sink. The three dams and the west embankment are Seismic Category 1 structures.

North Berm

The shoreline along Monticello Reservoir north of the plant and west of the North Dam has an earthen dike (the North Berm) constructed three feet above site grade. The North Berm is classified as a non-seismic, non-nuclear safety-related structure. The functional requirement of the North Berm is to protect nuclear safety-related structures and components from any adverse effects due to flooding.

System Evaluation Boundary

The evaluation boundary of Earthen Embankments includes earthen embankments associated with Service Water Pond and the North Berm.

System Intended Functions

The Earthen Embankments perform the following safety-related functions: Earthen Embankments provide a barrier to contain water inventory for plant shutdown and protection for safety-related SSCs. Therefore, Earthen Embankments are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Earthen Embankments provide protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Earthen Embankments are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

FSAR References

Additional details of the Earthen Embankments can be found in the FSAR, Sections 2.4.1, 2.4.3, 2.4.10, 2.5.6, and 3.1.2.4; Figure 2.4-1; and Table 3.2-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Earthen Embankments.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-9, Earthen Embankments.

The aging management review results for these component types are indicated in Table 3.5.2-9, Structures and Component Supports - Earthen Embankments - Aging Management Evaluation.

2.4.1.10 Electrical Manholes

System Description

Electrical Manholes are reinforced concrete structures buried underground that are supported on soil. Electrical Manholes have access openings, which allow personnel access, that are protected with reinforced concrete or metal covers. Electrical Manholes contain and support safety-related and nonsafety-related cables and components that are within the scope of license renewal.

System Evaluation Boundary

The evaluation boundary for the Electrical Manholes includes bolting; concrete elements associated with walls, slabs, foundations, and pads; and steel elements associated with manhole covers, ladders, and embedded steel.

System Intended Functions

Electrical Manholes perform the following safety-related functions: Electrical Manholes provide structural support, shelter, and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, Electrical Manholes are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of Electrical Manholes provide structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Electrical Manholes are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of Electrical Manholes are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, Electrical Manholes are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Electrical Manholes can be found in the FSAR, Sections 8.3.1.4.1 and 18.2.45; and Figure 8.3-2f.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Electrical Manholes.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-10, Electrical Manholes.

The aging management review results for these component types are indicated in Table 3.5.2-10, Structures and Component Supports - Electrical Manholes - Aging Management Evaluation.

2.4.1.11 Electrical Substation and Transformer Areas

System Description

The Electrical Substation and Transformer Area structures provide structural support to components relied on during a station blackout (SBO) event. Two separate offsite power sources are relied upon to recover from an SBO event. The two offsite power sources, which are considered the preferred power sources, are the Engineered Safety Features (ESF) transformer XTF-4 and Emergency Auxiliary Transformer XTF-31. The offsite high-voltage source for these transformers are the 115 kV Parr ESF transmission line (XTF-4) and the 230 kV Bus 3 (XTF-31).

The Electrical Substation and Transformer Areas are located south of the Turbine Building. Structures in these areas support electrical components that include transformers, circuit breakers, circuit switchers, cable bus, switchyard bus, transmission conductors, and lightning arrestors. Circuit breakers, transformers, and other electrical equipment are supported on concrete pads.

The Electrical Substation and Transformer Area structures that support components relied upon for coping with and recovering from an SBO event include:

Electrical Substation

Located in the Electrical Substation area are components that provide offsite power, including control and monitor functions, for the 230KV Substation Bus 3 Power Circuit Breaker XCB-8892, which are required to function for recovery from an SBO event. This includes the supports and foundations for circuit breaker XCB-8892, circuit switchers, Unit 1 Relay House, Substation Relay House, cable trenches, electrical manholes, switchyard bus, transmission towers, and lightning arrestors. Note that cable trenches and electrical manholes are addressed separately.

The Substation Relay House is a single-story structure that is founded on a reinforced concrete mat foundation and spread footings, and enclosed with masonry block walls. The roof system for the Substation Relay House consists of concrete slab covered with a built-up roof. The Unit 1 Relay House is a single-story precast concrete building and is supported by a concrete slab on grade. The Unit 1 Relay House and the Substation Relay House contain controls, relay protection, and monitoring equipment associated with the 230 kV switchyard busses.

Transformer Area Foundations and Supports

Foundations in the Transformer Area support transformers XTF-31 and XTF-4, voltage regulator XTF-6, electrical switch XES-8, and circuit switcher XES-4. Also, in this area are supports and foundations for the cable bus, switchyard bus, transmission conductors, circuit switchers, and lightening arrestors.

Transmission Towers and Foundations

Transmission towers and foundations support components (Emergency Auxiliary Transformers to 230 kV Substation) required to function during an SBO event. This includes the 230 kV Bus 3 line from XTF-31 to XCB-8892.

System Evaluation Boundary

The evaluation boundary for the Electrical Substation and Transformer Area structures includes structures that support electrical distribution system (e.g., cables, breakers, transformers, and switches) associated with the offsite SBO recovery path from the switchyard up to building interfaces. The buildings that house portions of SBO electrical distribution system that are located outside the Electrical Substation and Transformer Area are evaluated separately.

The evaluation boundary for the Electrical Substation and Transformer Area structures includes bolting; concrete elements associated with foundations, walls, pads, and slabs; doors; masonry block walls; roofing membrane; and steel elements associated with beams, columns, plates, trusses, poles, and embedded steel.

System Intended Functions

Electrical Substation and Transformer Area structures are relied upon for compliance with regulations for Station Blackout (10 CFR 50.63). Therefore, the Electrical Substation and Transformer Area structures are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Electrical Substation and Transformer Areas can be found in the FSAR, Section 8.4; and Figures 8.2-2a through 8.2-2d.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Electrical Substation and Transformer Areas.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-11, Electrical Substation and Transformer Areas.

The aging management review results for these component types are indicated in Table 3.5.2-11, Structures and Component Supports - Electrical Substation and Transformer Areas - Aging Management Evaluation.

2.4.1.12 Fuel Handling Building

System Description

The Fuel Handling Building is a steel frame superstructure founded on a reinforced concrete substructure. The roof system consists of steel decking covered with a built-up roof.

The foundation system for the Fuel Handling Building consists of a reinforced concrete mat formed by the bottom of the Spent Fuel Pool and Fuel Cask Pit, and is stepped up at the railroad bay. This concrete mat is supported by reinforced concrete piers which extend to the fill concrete adjacent to the Reactor and Auxiliary Buildings, and by reinforced concrete caissons which extend to competent rock on the north and east sides of the Fuel Handling Building mat, and supported by reinforced concrete piers that extend to the fill concrete adjacent to the Reactor and Auxiliary Buildings, and by reinforced concrete caissons that extend to competent rock on the north and east sides.

The Fuel Handling Building is a Seismic Category I structure and the building has two main floor levels. The principal elements of the building are the stainless steel lined spent fuel pool, cask loading pit, fuel transfer canal, decontamination area, excess liquid waste processing areas, and the new fuel storage area.

The spent fuel storage racks that are installed in the spent fuel pool are constructed of stainless steel. Boral panels are incorporated into the storage racks as a neutron-absorbing material.

System Evaluation Boundary

The evaluation boundary for the Fuel Handling Building includes aluminum elements associated with wall panel framing; bolting; concrete elements associated with beams, columns, walls, slabs, foundation, caissons, piers, knockdown walls, missile shields, and pads; doors; fuel storage rack neutron-absorbing sheets; roofing membrane; spent fuel pool liner plates; stainless steel elements associated with fuel transfer canal gate, new fuel storage racks, and spent fuel storage racks; and steel elements associated with beams, columns, ladders, grating, stairs, siding, missile shields, baseplates, and embedded steel.

System Intended Functions

The Fuel Handling Building performs the following safety-related functions: The structure provides structural support, shelter, and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Fuel Handling Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Fuel Handling Building provides structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Fuel Handling Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Fuel Handling Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Fuel Handling Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Fuel Handling Building can be found in the FSAR, Sections 3.8.4.1.6 and 3.8.5.1.5; Figures 3.8-58, 3.8-59, and 3.8-60; and Table 3.2-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Fuel Handling Building.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-12, Fuel Handling Building.

The aging management review results for these component types are indicated in Table 3.5.2-12, Structures and Component Supports - Fuel Handling Building - Aging Management Evaluation.

2.4.1.13 Intermediate Building

System Description

The Intermediate Building superstructure is an L-shaped reinforced concrete shear wall (box type) structure containing two main floor levels above the foundation and extending up to the low roof. Above the low roof is a partial third floor of reinforced concrete and a high roof. Built-up roofing exists over sections of the building.

The foundation system for the Intermediate Building consists of a reinforced concrete basement floor slab that acts in conjunction with a series of grade beams to transfer loads to the reinforced concrete caissons, shear/bearing walls, and concrete piers. The shear/bearing wall foundations and reinforced concrete caissons are founded on competent rock. The piers are founded on fill concrete that extends beyond the Reactor Building and Auxiliary Building.

The Intermediate Building is a Seismic Category I structure. The roof and exterior walls are designed to prevent damage to safety-related equipment from tornado generated missiles.

System Evaluation Boundary

The evaluation boundary for the Intermediate Building includes bolting; concrete elements associated with beams, columns, walls, slabs, foundation, caissons, piers, duct banks, missile shields, and pads; doors; roofing membrane; and steel elements associated with beams, columns, ladders, grating, siding, blow-off panels, stairs, missile shields, baseplates, and embedded steel.

System Intended Functions

The Intermediate Building performs the following safety-related functions: The structure provides structural support, shelter, and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Intermediate Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Intermediate Building provides structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Intermediate Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Intermediate Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the Intermediate Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Intermediate Building can be found in the FSAR, Sections 3.8.4.1.3 and 3.8.5.1.3; Figures 3.8-55 and 3.8-57; and Table 3.2-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Intermediate Building.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-13, Intermediate Building.

The aging management review results for these component types are indicated in Table 3.5.2-13, Structures and Component Supports - Intermediate Building - Aging Management Evaluation.

2.4.1.14 Miscellaneous Structural Commodities

System Description

The buildings and structures within the scope of subsequent license renewal contain Miscellaneous Structural Commodities that are within the scope of subsequent license renewal and are subject to aging management review.

Listed below are the Miscellaneous Structural Commodities that have been identified as being within the scope of subsequent license renewal and subject to aging management review:

- Fireproofing and fire barriers
- Electrical enclosures

- Guard pipes
- Penetration sleeves and seals
- Seismic gap filler material

Fireproofing and fire barriers are assemblies, which are designed and constructed to achieve specific fire resistance ratings, limit the spread of heat and fire, and restrict the movement of smoke.

Electrical enclosures include bus duct and switchgear enclosures, electrical panels and cabinets, junction, terminal, and pull boxes. The electrical panels and cabinets contain supports for electrical components located inside the enclosure. Gaskets provide a leak-tight condition from weather for the junction, terminal, and pull boxes. Electrical enclosures also include panels that are designed to contain potential internal fluid leakage.

Guard pipes are used as spray shields which protect adjacent equipment from postulated piping cracks or breaks.

Penetration sleeves are located in openings of walls, floors, roofs, or ceilings and allow components such as piping, conduits, duct banks, and tubing to be routed through the opening. Penetration seals are materials that are used to seal the penetration.

Seismic gaps are provided between adjacent structures to allow for relative motion between the structures. Although there are different configurations, in many configurations, the seismic gaps are covered and/or filled with a compressible material.

System Evaluation Boundary

The evaluation boundary for Miscellaneous Structural Commodities includes bolting; electrical enclosures; fireproofing and fire barriers associated with fire stops, fire wraps, fire barrier seals, coatings, and radiant energy shields; guard pipes; penetration seals; penetration sleeves; and seismic gap filler material that are located in buildings and structures that are within the scope of subsequent license renewal.

Fire damper assemblies are evaluated in the fire protection system. Fire barrier walls, doors, floors, and ceilings are evaluated with the associated buildings and structures that are within the scope of subsequent license renewal.

System Intended Functions

Miscellaneous Structural Commodities perform the following safety-related functions: Miscellaneous Structural Commodities provide structural support, shelter, and protection for safety-related SSCs. Therefore, Miscellaneous Structural Commodities are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Miscellaneous Structural Commodities provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Miscellaneous Structural Commodities are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Miscellaneous Structural Commodities are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, Miscellaneous Structural Commodities are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Miscellaneous Structural Commodities can be found in the FSAR, Sections 3.8.5, 6.2.6.2, and 8.3; Figure 3.8-52; and Appendix 8B.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Miscellaneous Structural Commodities Subcomponents.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-14, Miscellaneous Structural Commodities.

The aging management review results for these component types are indicated in Table 3.5.2-14, Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation.

2.4.1.15 NSSS Supports

System Description

The Nuclear Steam Supply System (NSSS) Supports are the plant structures and components that support the reactor coolant system loop piping and equipment and restrain it to the surrounding Reactor Building. NSSS supports permit unrestrained thermal growth of the supported systems, but restrain vertical, lateral, and rotational movement resulting from deadweight, seismic, and pipe break loadings. The following describes the major NSSS equipment supports:

Reactor Vessel Support

Supports for the reactor vessel are rectangular box structures beneath the vessel nozzles bolted to the primary shield wall concrete. Each box structure consists of a horizontal top plate that receives loads from the reactor vessel shoe, a horizontal bottom plate supported by and transferring loads to the primary shield wall concrete, and connecting vertical plates. The supports are air cooled to maintain the supporting concrete temperature within acceptable levels.

Steam Generator Support

The lower supports for the steam generator consist of vertical pin-ended columns bolted to the bottom of the steam generator support pads; and lateral support girders and pedestals that bear against horizontal bumper blocks bolted to the side of the generator support pads. The upper lateral steam generator support consists of a ring girder around the generator shell supported by struts. Loads are transferred from the equipment to the ring girder by means of a number of bumper blocks between the girder and generator shell.

Reactor Coolant Pump Support

The reactor coolant pump supports consist of pin-ended structural steel columns and lateral tie bars. A large diameter bolt connects each column and tie rod to a pump support pad. The outer ends of the tie rods have slotted pin holes to permit unrestrained lateral movement of the pump during plant heatup and cooldown, but provide lateral restraint for accident loadings.

Pressurizer Support

The pressurizer is supported at its base by bolting the flange ring to the supporting concrete slab. In addition, upper lateral support is provided near the vessel center of gravity by frames or struts extending horizontally from the compartment walls and bearing against the vessel lugs.

Other Class 1 Supports

In addition to the aforementioned equipment supports, NSSS Supports include supports for ASME Class 1 piping and components.

System Evaluation Boundary

The evaluation boundary for the NSSS Supports includes the supports for NSSS equipment and other ASME Class 1 piping and components. The evaluation boundary for NSSS Supports lies between the integral attachment on piping and equipment being supported and it includes bolting; grout; sliding surfaces; spring hangers; guides; stops; stainless steel element associated with support members; and steel elements associated with support members, bearing plates, baseplates, and connections. Exposed portions of the embedded components (i.e., end portion of threaded anchor and nut) and grout are evaluated with the NSSS Supports.

Concrete supporting structures (including the embedded portion of threaded anchor) are evaluated with the Containment. Integral attachments for the NSSS piping and equipment are evaluated for aging management with the specific NSSS equipment. Supports for ASME Class 2 and Class 3 piping and components are evaluated with Component Supports.

System Intended Functions

NSSS Supports provide structural support for safety-related SSCs. Therefore, NSSS Supports are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

FSAR References

Additional details of the NSSS Supports can be found in the FSAR, Sections 3.8.3.1.5.2 and 5.5.14; Figures 3.8-49 through 3.8-51, and 5.5-7 through 5.5-10.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the NSSS Supports.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-15, NSSS Supports.

The aging management review results for these component types are indicated in Table 3.5.2-15, Structures and Component Supports - NSSS Supports - Aging Management Evaluation.

2.4.1.16 Service Water Discharge Structure

System Description

The Service Water Discharge Structure is a reinforced concrete rectangular basin mostly buried in the West Embankment of the Service Water Pond. The foundation mat forms the floor of the basin. The foundation for the Service Water Discharge Structure consists of a reinforced concrete mat that bears partly on decomposed rock and partly on fill concrete that extends to the decomposed rock. An abutment wall forms the west end of the basin, and a high sill wall forms the east end. Wing walls form the north and south sides of the basin. Two 30-inch diameter service water pipes terminate at the abutment wall and are connected to the Service Water Discharge Structure by flexible connections.

The Service Water Discharge Structure is a Seismic Category I structure. The primary function of the Service Water Discharge Structure is to release service water into the Service Water Pond. The functional requirement of the Service Water Discharge Structure during and following a design basis event is that it does not collapse and result in an interruption of service water discharge.

System Evaluation Boundary

The evaluation boundary of the Service Water Discharge Structure includes concrete elements associated with beams, walls, slabs, and foundations.

The flexible connections between the service water pipes and the Service Water Discharge Structure are evaluated with Miscellaneous Structural Commodities Subcomponents.

System Intended Functions

The Service Water Discharge Structure performs the following safety-related functions: The structure provides a flow path for water required for reactor shutdown and the ability to maintain the reactor in a safe shutdown condition. Therefore, the Service Water Discharge Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

FSAR References

Additional details of the Service Water Discharge Structure can be found in the FSAR, Sections 3.8.4.1.9 and 3.8.5.1.9; Figure 3.8-64; and Table 3.2-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Service Water Discharge Structure.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-16, Service Water Discharge Structure.

The aging management review results for these component types are indicated in Table 3.5.2-16, Structures and Component Supports - Service Water Discharge Structure - Aging Management Evaluation.

2.4.1.17 Service Water Intake Structure

System Description

The Service Water Intake Structure is a reinforced concrete rectangular box culvert with two reinforced concrete wing walls at the intake end. The foundation mat forms the floor of the structure. The foundation for the Service Water Intake Structure consists of a reinforced concrete mat supported by compacted fill material, except for a portion of the inlet end, which rests on in-situ soils. A flexible joint separates the Service Water Intake Structure from the Service Water Pumphouse, which accommodates relative settlement and seismic movement. The structure extends into the Service Water Pond and is mostly buried in the West Embankment except for the intake end, which is submerged within the pond.

The Service Water Intake Structure is a Seismic Category I structure. The primary function of the Service Water Intake Structure is to extend the point at which water is drawn from the Service Water Pond into the Service Water Pumphouse. The functional requirement of the Service Water Intake Structure during and following a design basis event is that it does not collapse and result in a loss of supply water from the Service Water Pond to the Service Water Pumphouse.

System Evaluation Boundary

The evaluation boundary of the Service Water Intake Structure includes concrete elements associated with beams, walls, slabs, and foundations; and steel elements associated with trash racks, ladders, and embedded steel.

The flexible joint that separates the Service Water Intake Structure from the Service Water Pumphouse is evaluated with Miscellaneous Structural Commodities Subcomponents.

System Intended Functions

The Service Water Intake Structure performs the following safety-related functions: The structure provides a flow path for water required for reactor shutdown and the ability to maintain the reactor in a safe shutdown condition. Therefore, the Service Water Intake Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Service Water Intake Structure provides structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Service Water Intake Structure is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

FSAR References

Additional details of the Service Water Intake Structure can be found in the FSAR, Sections 3.8.4.1.8 and 3.8.5.1.8; Figures 3.8-62 and 3.8-63; and Table 3.2-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Service Water Intake Structure.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-17, Service Water Intake Structure.

The aging management review results for these component types are indicated in Table 3.5.2-17, Structures and Component Supports - Service Water Intake Structure - Aging Management Evaluation.

2.4.1.18 Service Water Pumphouse

System Description

The Service Water Pumphouse is a reinforced concrete building located on the West embankment of the Service Water Pond. The foundation for the Service Water Pumphouse consists of a reinforced concrete structural mat. The discharge pipe pits on the south side and the control areas on the west side of the Service Water Pumphouse are supported by buried reinforced concrete columns which extend to the supporting foundation mat. The entire structural mat is supported on compact fill that is in turn supported on a layer of in-situ soils (saprolite), then decomposed rock down to competent rock.

The Service Water Pumphouse is a Seismic Category I structure. The superstructure is a reinforced concrete building separated from the Service Water Intake Structure and from buried connecting pipes and electrical duct banks by flexible joints, which accommodate relative settlement and seismic movement. The primary function of the Service Water Pumphouse is to house the service water pumps that pump water from the Service Water Pond to supply the service water system.

System Evaluation Boundary

The evaluation boundary for the Service Water Pumphouse includes aluminum elements associated with louvers and screens; bolting; concrete elements associated with beams, columns, walls, slabs, foundation, duct banks, missile shields, and pads; doors; and steel elements associated with ladders, grating, stairs, beams, missile shields, baseplates, grating, trash racks, and embedded steel.

System Intended Functions

The Service Water Pumphouse performs the following safety-related functions: The structure provides structural support, shelter, and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Service Water Pumphouse is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Service Water Pumphouse provides structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Service Water Pumphouse is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Service Water Pumphouse is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Service Water Pumphouse is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3)

FSAR References

Additional details of the Service Water Pumphouse can be found in the FSAR, Sections 3.8.4.1.7 and 3.8.5.1.7; Figures 3.8-61 and 3.8-62; and Table 3.2-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Service Water Pumphouse.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-18, Service Water Pumphouse.

The aging management review results for these component types are indicated in Table 3.5.2-18, Structures and Component Supports - Service Water Pumphouse - Aging Management Evaluation.

2.4.1.19 Tank and Equipment Foundations

System Description

Tank and Equipment Foundations are reinforced concrete structures associated with tanks located in the yard (external to buildings and structures). The following Tank and Equipment Foundations are subject to aging management review:

Condensate Storage Tank Foundation

The Condensate Storage Tank foundation consists of a reinforced concrete mat supported by graded crushed stone fill material and an integral reinforced concrete ring wall that extends above the top of the foundation mat. The Condensate Storage Tank is secured to the foundation by anchor bolts embedded in the ring wall. Caulking is used at the tank external surface and concrete interface. The interior area of the ring wall is filled with clean dry sand to form a sand mat beneath the tank. A reinforced concrete valve pit is integrated into the south side of the foundation.

Carbon Dioxide Tank Foundation

The Carbon Dioxide Tank foundation is a reinforced concrete mat, supported on soil. The Carbon Dioxide Tank is secured to the mat foundation by embedded anchor bolts. This tank foundation is located just south of the Turbine Building.

Diesel Fuel Oil Truck Unloading Equipment Foundation

The Diesel Fuel Oil Truck Unloading Equipment Foundation is a reinforced concrete mat that is supported on soil. Equipment supported by the foundation are secured to the foundation by anchor bolts. This foundation is located east of the two underground diesel generator fuel oil storage tanks.

Alternate Seal Injection Diesel Generator and Control Panel Foundation

The foundation for the Alternate Seal Injection Diesel Generator and its associated control panel is a reinforced concrete mat that is supported on soil. The diesel generator and the control panel are secured to the foundation by anchor bolts. This foundation is located west of the Auxiliary Building.

System Evaluation Boundary

The evaluation boundary for the Tank and Equipment Foundations includes bolting; caulking and sealants; and concrete elements associated with walls, slabs, and foundations.

System Intended Functions

Tank and Equipment Foundations perform the following safety-related functions: Tank and Equipment Foundations provide structural support and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, Tank and Equipment Foundations are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Tank and Equipment Foundations provide structural support for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Tank and Equipment Foundations are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(2).

Tank and Equipment Foundations are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, Tank and Equipment Foundations are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Tank and Equipment Foundations can be found in the FSAR, Sections 2.5.4.10.3 and 9.2.6.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Tank and Equipment Foundations.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-19, Tank and Equipment Foundations.

The aging management review results for these component types are indicated in Table 3.5.2-19, Structures and Component Supports - Tank and Equipment Foundations - Aging Management Evaluation.

2.4.1.20 Turbine Building

System Description

The Turbine Building is a multi-story structure that is constructed with a reinforced concrete substructure and a steel framing superstructure. The steel framing superstructure is enclosed with metal siding. The roof is made of metal decking covered with a built-up roofing system. The foundation mat for the Turbine Building is primarily comprised of a reinforced concrete mat supported by fill material.

The Turbine Building is a non-Seismic Category I structure; however, the Turbine Building is designed to withstand earthquake loads and tornado wind loads to the extent required to prevent damage to Seismic Category I structures. The entire building is separated from other buildings to prevent load transfer during seismic events.

System Evaluation Boundary

The evaluation boundary for the Turbine Building includes aluminum elements associated with louvers, screens, and wall panel framing; bolting; concrete elements associated with beams, columns, walls, slabs, foundation, duct banks, and pads; doors; masonry block walls; roofing membrane; and steel elements associated with beams, columns, ladders, stairs, siding, decking, baseplates, grating, and embedded steel.

System Intended Functions

Structural integrity of the Turbine Building prevents collapse into adjacent structures containing safety-related components. Therefore, the Turbine Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(2).

The Turbine Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Anticipated Transients Without Scram (10 CFR 50.62). Therefore, the Turbine Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Turbine Building can be found in the FSAR, Sections 3.4, 3.6, 3.8.4.1.1, and 6.4.1.2; Figures 1.2-21, and 1.2-22; and Tables 3.2-2 and 9.5-1.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Turbine Building.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-20, Turbine Building.

The aging management review results for these component types are indicated in Table 3.5.2-20, Structures and Component Supports - Turbine Building - Aging Management Evaluation.

2.4.1.21 Water Treatment Building

System Description

The Water Treatment Building is a two-story steel framed structure founded on reinforced concrete mat foundation. The mat foundation is supported by fill material. The structure is enclosed with metal siding and masonry block walls. The roof consists of metal decking covered with a built-up roof. The intermediate floor is constructed of reinforced concrete and is supported by steel framing.

System Evaluation Boundary

The evaluation boundary for the Water Treatment Building includes aluminum elements associated with louvers, screens, and wall panel framing; bolting; concrete elements associated with beams, walls, slabs, foundation, and pads; doors; masonry block walls; roofing membrane; and steel elements associated with beams, columns, siding, decking, baseplates, and embedded steel.

System Intended Functions

The Water Treatment Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). The Water Treatment Building is not required for compliance with NFPA-805, but provides support and shelter for in-scope fire suppression hose reels and piping. Therefore, the Water Treatment Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the Water Treatment Building can be found in the FSAR, Section 1.2.3.2; Figure 2.5-46; and Tables 3.2-2 and 9.5-1.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Water Treatment Building.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-21, Water Treatment Building.

The aging management review results for these component types are indicated in Table 3.5.2-21, Structures and Component Supports - Water Treatment Building - Aging Management Evaluation.

Screening Results Tables: Containment, Structures and Component Supports

Table 2.4.1-1 Reactor Building

Structural Member	Intended Function(s)
Bolting	Pressure Boundary, Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Jet Impingement Shield, Missile Barrier, Pressure Boundary, Structural Support
Containment liner	Pressure Boundary, Structural Support
Equipment hatch, personnel access air lock, personnel escape air lock, and accessories (hinges, pins, closure mechanisms)	Enclosure Protection, Fire Barrier, Missile Barrier, Pressure Boundary, Structural Support
Moisture barriers	Enclosure Protection
Penetrations (electrical)	Pressure Boundary, Structural Support
Penetrations (mechanical)	Pressure Boundary, Structural Support
Primary shield wall	Enclosure Protection, Structural Support
Refueling cavity/fuel transfer canal liner	Water Barrier, Pressure Boundary, Structural Support
Seals and gaskets	Pressure Boundary
Service Level I coatings	Coating Integrity
Steel elements	Enclosure Protection, Fire Barrier, Flood Barrier, Jet Impingement Shield, Missile Barrier, Structural Support
Sump liners	Pressure Boundary, Structural Support
Tendon anchorage components	Structural Support
Tendons	Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-1, Containment Structure - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-2 Auxiliary Building

Structural Member	Intended Function(s)
Bellows	Pressure Boundary
Bolting	Structural Support
Caulking and sealants	Enclosure Protection
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Containment liner	Pressure Boundary
Doors	Enclosure Protection, Fire Barrier, Flood Barrier
Masonry block walls	Enclosure Protection, Flood Barrier
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-2, Structures and Component Supports - Auxiliary Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-3 Auxiliary Service Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Doors	Enclosure Protection
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-3, Structures and Component Supports - Auxiliary Service Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-4 Circulating Water Intake Structure

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Structural Support
Doors	Enclosure Protection, Fire Barrier
Masonry block walls	Enclosure Protection, Fire Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Filtration, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-4, Structures and Component Supports - Circulating Water Intake Structure - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-5 Component Supports

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection, Structural Support
Bolting	Structural Support
Grout	Structural Support
Sliding surfaces	Structural Support
Spring hangers; guides; stops	Structural Support
Stainless steel elements	Enclosure Protection, Structural Support
Steel elements	Enclosure Protection, Structural Support
Vibration isolation elements	Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-5, Structures and Component Supports - Component Supports - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-6 Control Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Doors	Enclosure Protection, Fire Barrier
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-6, Structures and Component Supports - Control Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-7 Diesel Generator Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Doors	Enclosure Protection, Fire Barrier
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-7, Structures and Component Supports - Diesel Generator Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-8 Duct Banks

Structural Member	Intended Function(s)
Concrete elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-8, Structures and Component Supports - Duct Banks - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-9 Earthen Embankments

Structural Member	Intended Function(s)
Earthen dike and embankment	Water Barrier, Source of Cooling, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-9, Structures and Component Supports - Earthen Embankments - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-10 Electrical Manholes

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Missile Barrier, Structural Support
Steel elements	Enclosure Protection, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-10, Structures and Component Supports - Electrical Manholes - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-11 Electrical Substation and Transformer Areas

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Doors	Enclosure Protection
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-11, Structures and Component Supports - Electrical Substation and Transformer Areas - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-12 Fuel Handling Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Doors	Enclosure Protection, Fire Barrier
Fuel storage rack neutron-absorbing sheets	Absorbs Neutrons
Roofing membrane	Enclosure Protection
Spent fuel pool liner plates	Enclosure Protection, Pressure Boundary, Structural Support
Stainless steel elements	Enclosure Protection, Pressure Boundary, Structural Support
Steel elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-12, Structures and Component Supports - Fuel Handling Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-13 Intermediate Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Doors	Enclosure Protection, Fire Barrier, Flood Barrier
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-13, Structures and Component Supports - Intermediate Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-14 Miscellaneous Structural Commodities

Structural Member	Intended Function(s)
Bolting	Structural Support
Electrical Enclosures	Enclosure Protection, Leakage Boundary (Spatial), Structural Support
Fireproofing and fire barriers	Enclosure Protection, Fire Barrier, Flood Barrier
Guard pipes	Enclosure Protection
Penetration seals	Enclosure Protection, Fire Barrier, Flood Barrier, Pressure Boundary
Penetration sleeves	Structural Support
Seismic gap filler material	Enclosure Protection, Fire Barrier

The aging management review results for these component types are indicated in Table 3.5.2-14, Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-15 NSSS Supports

Structural Member	Intended Function(s)
Bolting	Structural Support
Grout	Structural Support
Sliding surfaces	Structural Support
Spring hangers; guides; stops	Structural Support
Stainless steel elements	Structural Support
Steel elements	Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-15, Structures and Component Supports - NSSS Supports - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-16 Service Water Discharge Structure

Structural Member	Intended Function(s)
Concrete elements	Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-16, Structures and Component Supports - Service Water Discharge Structure - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-17 Service Water Intake Structure

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Missile Barrier, Pressure Boundary, Structural Support
Steel elements	Filtration, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-17, Structures and Component Supports - Service Water Intake Structure - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-18 Service Water Pumphouse

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Doors	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier
Steel elements	Enclosure Protection, Filtration, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-18, Structures and Component Supports - Service Water Pumphouse - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-19 Tank and Equipment Foundations

Structural Member	Intended Function(s)
Bolting	Structural Support
Caulking and sealants	Enclosure Protection
Concrete elements	Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-19, Structures and Component Supports - Tank and Equipment Foundations - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-20 Turbine Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Structural Support
Doors	Enclosure Protection, Fire Barrier
Masonry block walls	Enclosure Protection, Fire Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Fire Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-20, Structures and Component Supports - Turbine Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-21 Water Treatment Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Doors	Enclosure Protection
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-21, Structures and Component Supports - Water Treatment Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

2.5 SCOPING AND SCREENING RESULTS: ELECTRICAL AND INSTRUMENTATION AND CONTROL SYSTEMS

Scoping to determine the electrical and I&C systems that fall within subsequent license renewal was performed according to the methodology in Section 2.1.4 with results presented in Table 2.2-1. Results of electrical system scoping presented in Section 2.2 include not only plant electrical systems, but also switchyard components credited with restoring offsite power following a Station Blackout (SBO) event. The boundary for the SBO recovery path from both onsite and offsite power is depicted in a simplified diagram in Figure 2.1-1. Screening of in-scope electrical and I&C systems, as well as electrical and I&C components within in-scope mechanical systems, was performed in accordance with the methodology discussed in Section 2.1.5.

Identification of Electrical Components and Commodities

Screening of electrical and I&C components within the in-scope electrical, I&C, and mechanical systems used a bounding approach. Electrical and I&C components for the in-scope systems were assigned to commodity groups based on the listing in NUREG-2192, Table 2.1-6.

Application of Screening Criterion 10 CFR 54.21(a)(1)(i) to Electrical Components and Commodities

Following identification of electrical components and commodities, the criteria of 10 CFR 54.21(a)(1)(i) were applied to identify components and commodities that perform their functions without moving parts or without a change in configuration or properties. Commodities subject to an aging management review were identified by applying 10 CFR 54.21(a)(1) to identify those commodities that perform their function without moving parts or a change in configuration (“passive” components). This method provides the most efficient means for determining the electrical commodities subject to an aging management review since many electrical and I&C components are active. Passive commodity groups were reviewed, and any that did not perform an intended function were determined to not require an aging management review. The following electrical components and commodity groups were determined to meet the screening criteria of 10 CFR 54.21(a)(1)(i):

- Cable Bus
- Cables and Connections
    - Cable connections (metallic parts)
    - Connector contacts for electrical connections exposed to borated water leakage
    - Electrical insulation material for electrical cables and connections
    - Electrical penetration pigtails

  - Fuse Holder - not part of active equipment (insulation material)
  - Fuse Holder - not part of active equipment (metallic clamps)
  - Switchyard bus and connections
  - Transmission conductors
  - Transmission connections
  - Uninsulated ground conductors
- High Voltage Insulators

Elimination of Electrical Components with No License Renewal Intended Functions

The following electrical component (uninsulated ground conductors) was determined to not have a license renewal intended function and were eliminated from the electrical commodity groups:

Uninsulated Ground Conductors

The uninsulated ground conductor component group is comprised of grounding cable and associated connectors. Ground conductors are provided for equipment and personnel protection. They do not perform an intended function for license renewal. Therefore, uninsulated ground conductors are not within the scope of subsequent license renewal and are not subject to aging management review.

Application of Screening Criterion 10 CFR 54.21(a)(1)(ii) to Electrical Commodities and Components

The remaining passive commodity groups were screened consistent with 10 CFR 54.21(a)(1)(ii) to exclude those commodities that are subject to replacement based on a qualified life or specific time period from the requirements of an aging management review. The remaining passive commodities were determined to be subject to aging management review.

Subsequently, the screening criterion of 10 CFR 54.21(a)(1)(ii) was applied to the list of components and commodity groups that remained following application of the 10 CFR 21(a)(1)(i) criterion. 10 CFR 54.21(a)(1)(ii) allows the exclusion of those commodities that are subject to replacement based on a qualified life or specified time period. The only electrical commodities identified for exclusion by 10 CFR 54.21(a)(1)(ii) are electrical and I&C components and commodities included in the Environmental Qualifications of Electric Equipment aging management program. This is because electrical and I&C components and commodities included in the EQ Program have defined qualified lives and are replaced prior to the expiration of their qualified lives. No electrical and I&C components and commodities within the EQ Program are subject to aging management review in accordance with 10 CFR 54.21(a)(1)(ii). See Section 4.4 for the TLAA evaluation of the Environmental Qualification of Electric Equipment aging management program.

Electrical Components and Commodity Groups Subject to Aging Management Review

The remaining electrical components and commodity groups, all or part of which are not in the EQ Program, require aging management review and are discussed in Sections 2.5.1.1, 2.5.1.2, and 2.5.1.3 below.

Components that provide support functions for electrical and I&C components, for example, electrical panels and enclosures, instrument racks, cable tray, and conduit, are assessed with the structural support commodity group in Section 2.4.

2.5.1 Electrical Component Groups

2.5.1.1 Cable Bus

System Description

The electrical commodity group identified as “Cable Bus” includes the following component groups:

- Cable bus enclosure assembly (includes Tap Box enclosure)
- Cable bus insulation, insulators

Cable bus is a specific subset of insulated cables and is included as a separate commodity type. The electrical components included within the component groups consist of electrical conductors and termination devices that deliver voltage, current, and/or signals from sources to end use devices, materials that insulate electrical conductors and terminations, and metal enclosures that shelter and protect. The cable bus system is an electrical power feeder system that uses fully insulated, single conductor power cables.

Cable bus is constructed of an arrangement of medium-voltage insulated cables separated by insulating spacers to maintain amperage and voltage rating, and it is installed in metallic cable tray enclosures. These electrical components are further described below.

Cable Bus Enclosure Assembly

Cable bus enclosure assemblies consist of a ventilated metallic (aluminum, galvanized steel, steel) enclosure for the cable bus system, and it is designed to withstand the mechanical forces encountered from short circuit currents. Just like a typical cable tray system, the cable bus enclosure provides structural support, and allows for directional changes both horizontally and vertically. Top covers are typically removable to allow access to the insulated cables and the cable supports. Cable bus enclosure assemblies includes any of the required directional fittings and entrance fittings (wall or floor penetrations) that are connected.

Tap box enclosures are similar in construction and material to cable bus enclosures. Tap boxes are necessary for intermediate load tapping and are typically used when a continuous conductor (insulated cable) is not used. The cable bus enclosure assembly includes the enclosure of the connected “tap boxes”. Tap box connections are included as a specific connection type with electrical connections.

Box connector enclosures are similar in construction and material to cable bus enclosures. Box connectors are used to terminate cable bus at end components such as switchgear or transformers. The cable bus enclosure assembly includes the enclosure of the connected “box connectors”.

Cable bus enclosure assembly supports are included as a bulk structural commodity similar to cable tray and conduit supports.

Cable Bus Insulation, Insulators

The support or spacing blocks of a cable bus system are used to maintain spacing and phasing arrangement for the insulated electrical cables. These support blocks are designed to maintain the free air conductor rating of the insulated cables. The support blocks are isolated from ground inside the enclosure assembly.

Cable bus is not included in the Environmental Qualification (EQ) program. Therefore, cable bus meets the screening criteria for 10 CFR 54.21(a)(1)(ii) and is subject to aging management review.

System Evaluation Boundary

The Cable Bus commodity group includes the following sections of bus duct (cable bus) including Tap Boxes:

- Cable bus (XBD0015A) connecting ESF transformer XFT4 and voltage regulator XTF6 to bus XSW1DX switchgear breaker XSW1DX 01 (a)(3)
- Cable bus (XBD0015C, XBD0016B) connecting bus XSW1DX switchgear breaker XSW1DX 02 to bus XSW1DB Breaker XSW1DB 01 (a)(3) (This includes the tap box between XBD0015C and XBD0016B)
- Cable bus (XBD0017) connecting bus XSW1DB switchgear breaker XSW1DB 16 to bus XSW1DA Breaker XSW1DA 15 (a)(3)
- Cable bus (XBD0015D) connecting bus XSW1DX switchgear breaker XSW1DX 05 to bus XSW1DA breaker XSW1DB 01 (a)(3)
- Cable bus (XBD0014D) connecting emergency auxiliary transformer XFT31 to bus XSW1DB switchgear breaker XSW1DB 19 (a)(3)
- Cable bus (XBD-19A) connecting ESF transformer XTF0004 and 7.2KV transfer and disconnect switch XES0008 19 (a)(3)
- Cable bus (XBD-20A) XBD-15A junction box connecting XSW1DX and XES0008 (a)(3)
- Cable bus (XBD-21A) connecting the XTF0004 7.2KV voltage regulator XTF0006 and XES0008 (a)(3)

Cable bus enclosure assembly supports are included as a bulk structural commodity similar to cable tray and conduit supports.

System Intended Functions

Components in the Cable Bus commodity group perform the intended functions of conducts electricity, insulates, and enclosure protection are relied on for compliance with regulations for Station Blackout (10 CFR 50.63) and Fire Protection (10 CFR 50.48). Therefore, Cable Bus is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the cable bus can be found in the FSAR, Section 8.2.1.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the cable bus.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.5.1-1, Cable Bus.

The aging management review results for these component types are indicated in Table 3.6.2-1, Electrical and Instrumentation and Controls - Cable Bus - Aging Management Evaluation.

2.5.1.2 Cables And Connections

System Description

The electrical commodity group identified as "Cables and Connections" includes the following electrical and instrumentation and control (I&C) component groups:

- Cable connections (metallic parts)
- Connector contacts for electrical connections exposed to borated water leakage
- Fuse holder - (insulation material not part of active equipment)
- Fuse holder - (metallic clamps not part of active equipment)
- Electrical insulation material
- Switchyard bus and connections
- Transmission conductors
- Transmission connectors

Numerous insulated cables and connections are included in the EQ program and, therefore, are not subject to an aging management review in accordance with the screening criteria of 10 CFR 54.21(a)(1)(ii). Insulated cables and connections not included in the EQ program meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

The electrical and I&C components included within the component groups consist of electrical conductors and termination devices that deliver voltage, current, and/or signals from sources to end use devices and are passive in nature. These electrical components are further described below.

Cable Connections (Metallic Parts)

The cable connections (metallic parts) component group includes metallic portions of electrical terminations that are not included in the EQ program. Termination devices within this component group include compression type terminal lugs, bolted connections, splices, and terminal blocks. The Cable Bus Tap Box connections are included as a specific cable connection type in the XI.E6 Aging Management Program, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements".

Connector Contacts for Electrical Connections Exposed to Borated Water Leakage

The connector contacts for electrical connections exposed to borated water leakage component group includes connector contacts, not included in the EQ program, that are exposed to borated water leakage.

Fuse Holder - (Insulation Material Not Part of Active Equipment)

The fuse holder - not part of active equipment (insulation material) component group includes fuse holders that are not part of active equipment and are not included in the EQ program. The insulation material for these fuse holders includes the mounting block for metallic components.

Fuse Holder - (Metallic Clamps Not Part of Active Equipment)

The fuse holder - not part of active equipment (metallic clamps) component group includes fuse holders that are not part of active equipment and are not included in the EQ program. The metallic portions of these fuse holders include spring-loaded clips and bolted lugs to connect the fuse ends.

Electrical Insulation Material

The electrical insulation material for electrical cables and connections component group includes insulation material for the following component groups that are not included in the EQ program:

- Cables and connections
- Cables and connections used in instrumentation circuits
- Inaccessible or below ground medium-voltage cable
- Inaccessible or below ground I&C cable
- Inaccessible or below ground low-voltage power cable

Underground insulated I&C cable that is part of the station blackout (SBO) offsite power recovery path for breaker and transformer control is included within the scope of subsequent license renewal.

Switchyard Bus and Connections

The switchyard bus and connections component group includes the passive, long-lived switchyard components and connections that are part of the power feeds credited for recovery of offsite power for the two GDC-17 offsite power paths to the engineered safety features (ESF) and emergency auxiliary transformers following an SBO event. The boundary for these power feeds is the first active switchyard load break device (e.g. circuit breaker or load interrupting motor operated circuit switcher) and their associated disconnect switches downstream of 230 kV switchyard bus 3 and 115 kV Parr line to the emergency auxiliary and ESF transformers. These components include the 5" tubular aluminum switchyard bus, bare aluminum cable, and termination devices that connect active components (disconnect switches and circuit breakers) from switchyard 230 kV and 115 kV buses to the emergency auxiliary and ESF transformers.

Although these components are within the station boundary at the ESF transformer, their material type, environment, and aging effects are similar to corresponding switchyard components. Therefore, they are included in the switchyard bus and connections component group for evaluation.

Transmission Conductors

The transmission conductor component group includes the passive, long-lived 230 kV overhead transmission conductors that provide recovery of offsite power for one of the two GDC-17 offsite power paths to the emergency auxiliary transformer following an SBO event. These transmission conductors are 795 kcmil aluminum conductor steel reinforced (ACSR) bare (uninsulated) cables.

Transmission Connections

The transmission connections component group includes the connections for the 230 kV transmission conductors that provide recovery of offsite power for the two GDC-17 offsite power paths to the emergency auxiliary and ESF transformers following an SBO event. These transmission connectors include compression terminals and bolted connections to welded switchyard bus connections.

System Evaluation Boundary

The cable and connections commodity group includes those electrical and I&C components listed in the cable and connections component groups that are used in systems determined to be in-scope for subsequent license renewal. The cable and connections commodity group was evaluated against 10 CFR 54.21(a)(1)(ii) and the cable and connections determined to be included in the EQ program are not subject to aging management review. Therefore, only the non-EQ cable and connections are subject to aging management review.

In addition to the station electrical systems, switchyard components credited in the restoration of offsite power following an SBO event were included within the scope of subsequent license renewal. The switchyard components credited for recovery from an SBO event begin at the first active switchyard load break device (e.g.: circuit breaker or load interrupting motor operated disconnect) and associated disconnect switches downstream of 115 kV Parr line and 230 kV Bus 3 and continue through to the ESF and emergency auxiliary transformers XFT4 and XFT31 and the station switchgear to the final safety-related buses XSW1DA and XSW1DB.

Stored Equipment

The cables and connections commodity group includes cable and terminal lugs stored in the warehouse at VCSNS for the purpose of energizing RHR pumps from an alternate source. This stored equipment is within the scope of subsequent license renewal.

Support Components and Structures

Components that support electrical and I&C components, for example cable trays, conduit, structural supports, steel poles, racks and panels, are assessed as part of the structural evaluation.

System Intended Functions

Components in the cables and connections commodity group perform the intended functions of conducts electricity and insulates for circuits that supply electrical power, control and indication signals to safety-related components. Therefore, cables and connections are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Components in the cables and connections commodity group perform the intended functions of conducts electricity and insulates for circuits that are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, cables and connections are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the cables and connections can be found in the FSAR, Sections 8.1, 8.2, 8.3, 8.4, Table 8.1-3.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the cables and connections.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.5.1-2, Cables And Connections.

The aging management review results for these component types are indicated in Table 3.6.2-2, Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation.

2.5.1.3 High Voltage Insulators

System Description

The electrical commodity group identified as "High-Voltage Insulators" includes those station post and suspension insulators that support overhead conductors (transmission conductors and switchyard bus) that are part of the SBO offsite power recovery path. High-voltage insulators are passive in nature. The insulating portion of high-voltage insulators is made of porcelain. The high-voltage insulator commodity group was evaluated against 10 CFR 54.21(a)(1)(ii) and determined to not be included in the EQ program. Therefore, high-voltage insulators are subject to aging management review.

Porcelain is a ceramics that experiences the external aging effects of reduced insulation resistance from excessive surface contamination. Porcelain relies on surface rinsing from precipitation or mechanical washing to clean contaminants from the shed surfaces. Porcelain has been in service in the utility industry for over 60 years worldwide and is considered to be a mature technology and generally standardized.

The porcelain insulators are cap and pin (suspension) insulators and experience the same aging effect of loss of material from corrosion and mechanical wear. Inspection for mechanical wear (visual) is conducted. The insulating material for porcelain has the aging effect of reduced insulation resistance from excessive surface contamination. Inspection for excessive surface contamination (visual) is conducted.

System Evaluation Boundary

The high-voltage insulators commodity group includes SBO offsite power recovery path insulators that support the 115 kV and 230 kV transmission conductors and switchyard bus in the overhead lines that are available as the two GDC-17 offsite power paths to the ESF transformer XFT4, and the emergency auxiliary transformer XFT31. The 115 kV overhead transmission and switchyard conductors connect the PARR ESF circuit switcher (XES 4) that feeds the ESF transformer (XTF 4) high voltage side. The 7.2 kV cable bus connects the ESF transformer low voltage side to the Turbine Building 7.2 kV switchgear XSW1DX via transfer switch XES 8 and voltage regulator XTF 6, which does not have high voltage insulators. The 230 kV overhead transmission and switchyard conductors connect the 230kV switchyard beaker (XCB 8892) that feeds the emergency auxiliary transformer (XTF-31) high voltage side. The 7.2 kV cable bus connects the emergency auxiliary transformer low voltage side to the Intermediate Building 7.2 kV switchgear XSW1DB, which does not have high voltage insulators. The boundary for the SBO offsite power recovery path is the first active switchyard load break device (e.g.: circuit breaker or load interrupting disconnect or circuit switcher) and their associated disconnect switches downstream of 230 kV switchyard bus 3, and 115 kV Parr ESF line.

Components that support high-voltage insulators, for example structural supports and steel poles, are assessed as part of the structural evaluation.

System Intended Functions

Components in the high-voltage insulators commodity group perform the intended function of insulates for circuits that are relied upon for compliance with regulations for Station Blackout (10 CFR 50.63). Therefore, High-Voltage Insulators are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

FSAR References

Additional details of the high voltage insulators can be found in the FSAR, Section 8.3, Table 8.1-3.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the high voltage insulators.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.5.1-3, High Voltage Insulators.

The aging management review results for these component types are indicated in Table 3.6.2-3, Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation.

Screening Results Tables: Electrical and Instrumentation and Controls Commodity Groups

Table 2.5.1-1 Cable Bus

Subcomponent	Intended Function(s)
Cable bus enclosure assembly (includes Tap Box enclosure)	Enclosure Protection
Cable bus insulation, insulators	Insulate

The aging management review results for these component types are indicated in Table 3.6.2-1, Electrical and Instrumentation and Controls - Cable Bus - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.5.1-2 Cables And Connections

Subcomponent	Intended Function(s)
Cable connections (metallic parts)	Conducts Electricity
Connector contacts for electrical connections exposed to borated water leakage	Conducts Electricity
Fuse Holder - Not Part of Active Equipment (Insulation Material)	Insulate
Fuse Holder - Not Part of Active Equipment (Metallic Clamps)	Conducts Electricity
Insulation Material for Electrical Cable and Connections Used in Instrumentation Circuits	Insulate
Insulation Material for Electrical Cables and Connections	Insulate
Insulation Material for Inaccessible or Below Ground Instrumentation and Control Cable	Insulate
Insulation Material for Inaccessible or Below Ground Low Voltage Power Cable	Insulate
Insulation Material for Inaccessible or Below Ground Medium Voltage Cable	Insulate
Switchyard bus and connections	Conducts Electricity
Transmission conductors	Conducts Electricity
Transmission connectors	Conducts Electricity

The aging management review results for these component types are indicated in Table 3.6.2-2, Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.5.1-3 High Voltage Insulators

Subcomponent	Intended Function(s)
High Voltage Insulators	Insulate

The aging management review results for these component types are indicated in Table 3.6.2-3, Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

3.0 AGING MANAGEMENT REVIEW RESULTS

This chapter provides the results of the aging management review for those structures and components identified in Table 2.2-1 as being subject to aging management review.

Organization of this chapter is based on Tables 3.1-1 through 3.6-1 of NUREG-2192, “Standard Review Plan for the Review of Subsequent License Renewal Applications for Nuclear Power Plants,” dated July 2017. (Reference 1.7-5).

- The major sections of this chapter are:
- Aging Management of Reactor Vessel, Internals, and Reactor Coolant System (Section 3.1)
- Aging Management of Engineered Safety Features (Section 3.2)
- Aging Management of Auxiliary Systems (Section 3.3)
- Aging Management of Steam and Power Conversion System (Section 3.4)
- Aging Management of Containments, Structures, and Component Supports (Section 3.5)
- Aging Management of Electrical and Instrumentation and Controls (Section 3.6)

Descriptions of the service environments that were used in the mechanical systems aging management review to determine aging effects requiring management are included in Table 3.0-1, Mechanical System Service Environments. The environments used in the aging management reviews are listed in the Environment column. The third column identifies one or more of the NUREG-2191 environments that were used when comparing the Aging Management Review results to the NUREG-2191 results. The Electrical and Structural aging management reviews use environment names consistent with the assigned NUREG-2191 items. The definitions of those environments correspond to the definitions in NUREG-2191 section IX.D.

Most of the Aging Management Review (AMR) results information in Section 3 is presented in the following two tables:

Table 3.x.1 - where ‘3’ indicates the SLRA section number, ‘x’ indicates the subsection number from NUREG-2191, and ‘1’ indicates that this is the first table type in Section 3. For example, in the Reactor Vessel, Internals, and Reactor Coolant System subsection, this table would be number 3.1.1, in the Engineered Safety Features subsection, this table would be 3.2.1, and so on. For ease of discussion, this table will, hereafter, be referred to in this Section as “Table 1.”

Table 3.x.2-y - where ‘3’ indicates the SLRA section number, ‘x’ indicates the subsection number from NUREG-2191, and ‘2’ indicates that this is the second table type in Section 3; and ‘y’ indicates the table number for a specific system. For example, for the reactor vessel, within the Reactor Vessel, Internals, and Reactor Coolant System subsection, this table would be 3.1.2-1 and for the reactor vessel internals, it would be Table 3.1.2-2. For the reactor building spray system, within the Engineered Safety Features (ESF) subsection, this table would be 3.2.2-1. For the next system

within the ESF subsection, it would be Table 3.2.2-2. For ease of discussion, this table will, hereafter, be referred to in this section as “Table 2.”

Table Description

Table 1

The purpose of Table 1 is to provide a summary comparison of how the facility aligns with the corresponding tables of NUREG-2192. The table is essentially the same as Tables 3.1-1 through 3.6-1 provided in NUREG-2192, except that the “New, Modified, Deleted, Edited Item,” “ID” and “Type” columns have been replaced by an “Item Number” column, and the “GALL-SLR Item” column has been replaced by a “Discussion” column.

The “Item Number” column provides the reviewer with a means to cross-reference from Table 2 to Table 1.

The “Discussion” column is used to provide clarifying or amplifying information. The following are examples of information that might be contained within this column:

- “Further Evaluation Recommended” information or reference to where that information is located
- The name of a plant specific aging management program being used, if applicable
- Exceptions to the NUREG-2191 assumptions, if applicable
- A discussion of how the line is consistent with the corresponding line item in NUREG-2191, when that may not be intuitively obvious
- A discussion of how the item is different than the corresponding line item in NUREG-2191 when it may appear to be consistent (e.g., when there is exception taken to an aging management program that is listed in NUREG-2191), if applicable

The format of Table 1 provides the reviewer with a means of aligning a specific Table 1 item with the corresponding NUREG-2192 table item, thereby allowing for the ease of checking consistency.

Table 2

Table 2 provides the detailed results of the aging management reviews for those components identified in SLRA Section 2 as being subject to aging management review. There is a Table 2 for each of the systems within a Chapter 3 Section grouping. For example, the Engineered Safety Features System Group contains tables specific to the reactor building spray system, refueling water system, residual heat removal system and safety injection system. Table 2 consists of the following nine columns:

- Component Type
- Intended Function
- Material
- Environment
- Aging Effect Requiring Management
- Aging Management Programs
- NUREG-2191 Item
- Table 1 Item
- Notes

Component Type - The first column identifies all of the component types from Section 2 of the SLRA that are subject to aging management review. They are listed in alphabetical order.

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

Material - The third column lists the particular materials of construction for the component type.

Environment - The fourth column lists the environments to which the component types are exposed. Service environments are indicated and a list of mechanical system service environments is provided in Table 3.0-1. The Electrical and Structural aging management reviews use environment names consistent with the assigned NUREG-2191 items. The definitions of those environments correspond to the definitions in NUREG-2191, Section IX.D.

Aging Effect Requiring Management - As part of the aging management review process, the aging effects that are required to be managed in order to maintain the intended function of the component type are identified for the material and environment combination. These aging effects requiring management are listed in the fifth column.

Aging Management Programs - The aging management programs used to manage the aging effects requiring management are listed in the sixth column of Table 2. Aging management programs are described in Appendix B.

NUREG-2191 Item - Each combination of component type, material, environment, aging effect requiring management, and aging management program that is listed in Table 2, is compared to NUREG-2191, with consideration given to the standard notes, to identify consistency. Consistency is documented by noting the appropriate NUREG-2191 item number in the seventh column of Table 2. If there is no corresponding item number in NUREG-2191, this field in column seven is marked “None.” Thus, a reviewer can readily identify the correlation between the plant-specific tables and the NUREG-2191 tables.

Table 1 Item - Each combination of component, material, environment, aging effect requiring management, and aging management program that has an identified NUREG-2191 item number must also have a Table 3.x.1 line item reference number. The corresponding line item from Table 1 is listed in the eighth column of Table 2. If there is no corresponding item in NUREG-2191, this field in column eight is marked “None.” The Table 1 Item allows correlation of the information from the two tables.

Notes - The notes provided in each Table 2 describe how the information in the table aligns with the information in NUREG-2191. Each Table 2 contains standard lettered notes and, if applicable, plant-specific numbered notes.

The standard lettered notes (e.g., A, B, C) provide standard information regarding comparison of the aging management review results with the NUREG-2191 Aging Management Table line item identified in the seventh column. In addition to the standard lettered notes, numbered plant-specific notes provide additional clarifying information when appropriate.

Table Usage

Table 1

The reviewer evaluates each item in Table 1 by moving from left to right across the table. Since the Component, Aging Effect, Aging Management Programs and Further Evaluation Recommended information is taken directly from NUREG-2192, no further analysis of those columns is required. The information intended to help the reviewer in this table is contained within the Discussion column. Here the reviewer will be given plant-specific information necessary to determine, in summary, how the evaluations and programs align with NUREG-2191. This may be in the form of descriptive information within the Discussion column or the reviewer may be referred to other locations within the SLRA for further information. A statement of “Consistent with NUREG-2191” means that the Table 2 items that link to that Table 1 item are consistent with the material, environment, aging effect, and program(s) associated with the assigned NUREG-2191 item, followed by any clarifications or exceptions that may apply.

Table 2

Table 2 contains all of the Aging Management Review information for the plant, whether or not it aligns with NUREG-2191. For a given item within the table, the reviewer can see the intended function, material, environment, aging effect requiring management and aging management program combination for a particular component type within a system. Within each system or structure, the intended functions for each component type are consolidated for table listing. In addition, if there is a correlation between the combination in Table 2 and a combination in

NUREG-2191, this will be identified by a referenced item number in column seven, NUREG-2191 Item. The reviewer can refer to the item number in NUREG-2191, if desired, to verify the correlation. If the column contains “None,” no corresponding combination in NUREG-2191 was found. As the reviewer continues across the table from left to right, within a given item, the next column is labeled Table 1 Item. If there is a reference number in this column, the reviewer is able to use that reference number to locate the corresponding item in Table 1 and see how the aging management program for this particular combination aligns with NUREG-2191.

Table 2 provides the reviewer with a means to navigate from the components subject to Aging Management Review (AMR) in SLRA Section 2 all the way through the evaluation of the programs that will be used to manage the effects of aging of those components.

Cumulative Fatigue Damage and TLAAs in Table 2

A fatigue analysis is considered to be a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3 when it is within the current licensing basis and is based upon transient cycle assumptions associated with the current operating term. This includes explicit ASME Code, Section III, Class 1 analysis for components and ANSI B31.7 Class 1 analysis for piping as well as implicit ASME Code, Section III, Class 2 and 3 analysis for piping based on ANSI B31.1. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). Table 1 and Table 2 include an entry in the Aging Management Program column indicating “TLAA” for each line item that has a component for which a fatigue TLAA (explicit or implicit) has been identified. See SLRA Section 4.3 for details regarding the fatigue design bases, fatigue TLAAs identified, and TLAA evaluations for the subsequent period of extended operation.

Table 3.0-1 Mechanical System Service Environments

VCSNS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison (1)
Air - dry	Air that has been treated to reduce its dew point well below the system operating temperature. Within piping systems, unless otherwise specified, this environment may be either internal or external.	Air, Air - dry
Air – indoor, uncontrolled	Indoor air with temperatures higher than the dew point. Condensation can occur but only rarely, equipment surfaces are normally dry. For high temperature systems, this environment includes the potential for elevated temperatures that supports cumulative fatigue damage. This name is also used to describe the internal environment of undried compressed air.	Air, Air – indoor, uncontrolled, System temperature up to 288°C (550°F) System temperature up to 340°C (644°F)
Air - outdoor	The outdoor environment consists of moist, atmospheric air at temperatures and humidity, and exposure to weather, including precipitation and wind. The component is exposed to air and local weather conditions. Outdoor air does not include the potential to pool water; outdoor environments with the potential for pooled water are called raw water, condensation, or soil (for tank bottoms).	Air, Air – outdoor
Air with borated water leakage	Indoor air in areas that contain borated water systems have the potential for borated water leakage, with management by the Boric Acid Corrosion program. This environment is assigned to steel, gray cast iron, ductile iron, and copper alloy (>15% Zn) in areas with systems containing borated water. It is not assigned to materials which are not susceptible to boric acid corrosion.	Air with borated water leakage
Closed-cycle cooling water	Treated water subject to the Closed Treated Water Systems chemistry program. Closed-cycle cooling water describes the environment in treated closed cooling and heating systems. Closed-cycle cooling water is aligned to GALL rows for Treated water for locations susceptible to erosion.	Closed-cycle cooling water, Treated water
Closed-cycle cooling water >60°C (>140°F)	Treated water subject to the Closed Treated Water Systems chemistry program. Closed-cycle cooling water systems above 60 °C [>140 °F] exceed the threshold for SS SCC.	Closed-cycle cooling water, Closed-cycle cooling water >60°C (>140°F)

Table 3.0-1 Mechanical System Service Environments

VCSNS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison (1)
Concrete	The external environment of components embedded in concrete.	Concrete
Condensation	Condensation on the surfaces of systems with temperatures below the dew point, or in the associated drains. Condensation may be internal or external. Condensation includes the potential for concentration of contaminants. Elastomers in condensation are matched to the GALL-SLR environment of “Air” for loss of material and flow blockage. Stainless steel bolting in condensation is matched to GALL-SLR environment of “Air” for cracking.	Air, Condensation
Diesel exhaust	Gases, fluids, and particulates present in diesel engine exhaust.	Diesel exhaust
Fuel oil	Diesel oil, No. 2 oil, or other liquid hydrocarbons used to fuel diesel engines. Fuel oil used for combustion engines may include water contamination. The fuel oil environment does not exceed the threshold temperature for cracking of stainless steel (140°F).	Fuel oil
Gas	Environments of inert or non-reactive gases. Oxygen is not considered to be present in this environment. Gas is used to describe hydrogen, nitrogen, freon, carbon dioxide and halon environments. Reactive replacement gases for freon and halon are not included in this environment.	Gas
Lubricating oil	Lubricating oils are low-to-medium viscosity hydrocarbons, with the possibility of containing contaminants and/or moisture, used for bearing, gear, and engine lubrication. This name is also used to describe non-water based hydraulic fluid.	Lubricating oil
Raw water	Raw, untreated, river, lake, or groundwater. Raw water does not exceed the threshold temperature for SCC of stainless steels (140°F).	Raw water, Raw water (potable)

Table 3.0-1 Mechanical System Service Environments

VCSNS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison (1)
Reactor coolant	Treated water in the reactor coolant system and connected systems at or near full operating temperature. Reactor coolant includes the steam phase. The Reactor coolant environment name is used for the reactor coolant system, the reactor vessel and internals components. The environment for connected piping and systems may be referred to as one of the treated borated water environments. Reactor coolant is aligned to GALL rows for Treated borated water for locations susceptible to erosion.	Reactor coolant, Treated borated water
Reactor coolant >250°C (>482°F)	Water in the reactor coolant system above the thermal embrittlement threshold for CASS. Components in this environment are also matched to GALL-SLR environment items without the temperature threshold for other aging effects.	Reactor coolant, Reactor coolant >250°C (>482°F)
Reactor coolant >250°C (>482°F) and neutron flux	Water in the reactor coolant system above the thermal embrittlement threshold for CASS, and above the fluence threshold for neutron embrittlement.	Reactor coolant and neutron flux
Reactor coolant and neutron flux	Reactor core environment that will result in a neutron fluence exceeding the threshold for management at the end of the subsequent license renewal term. The reactor coolant environment name is used for the reactor vessel and internals components.	Reactor coolant, Reactor coolant and neutron flux
Soil	External environment for components exposed to soil or buried in the soil, including groundwater in the soil. The soil around buried piping at VCSNS does not correspond to a “carbonate/bicarbonate environment” identified as applicability criterion for cracking of steel in soil in NUREG-2191, items V.E.E-420, VII.I.A-425, and VIII.H.S-420(2).	Soil
Steam	The vapor phase of treated water. Steam may be superheated or saturated.	Steam
Treated borated water	Borated (PWR) water is a controlled water system. The chemical and volume control system maintains the proper water chemistry in the reactor coolant system while adjusting the boron concentration during operation to match long-term reactivity changes in the core.	Reactor Coolant, Treated borated water

Table 3.0-1 Mechanical System Service Environments

VCSNS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison (1)
Treated borated water >60°C (>140°F)	Treated water with boric acid in PWR systems above the 60°C [>140°F] SCC threshold for stainless steel. Non-Class 1 piping in Treated borated water >60°C (>140°F) with a fatigue TLAA is aligned to GALL rows for Reactor coolant. Nickel alloy components in Treated borated water >60°C (>140°F) susceptible to cracking (SCC) are aligned to GALL rows for Reactor coolant.	Reactor Coolant, Treated borated water, Treated borated water >60°C (>140°F)
Treated water	Treated water is demineralized water. Treated water could be deaerated and include corrosion inhibitors, biocides, other additives such as glycol, or some combination of these treatments. This environment may represent liquid or steam/vapor.	Secondary feedwater, System temperature up to 340°C (644°F), Treated water
Treated water >60°C (>140°F)	Treated water above the 60°C (140°F) stress corrosion cracking threshold for stainless steel. This environment may represent liquid or steam/vapor. Components in this environment are also matched to GALL-SLR environment items without the temperature threshold for other aging effects.	Secondary feedwater, System temperature up to 340°C (644°F), Treated water, Treated water >60°C (>140°F)

Table 3.0-1 Mechanical System Service Environments

VCSNS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison (1)
Underground	Underground piping and tanks are below grade, but are contained within a tunnel or vault such that they are in contact with air and are located where access for inspection is limited (e.g., special lifting equipment is required to gain access to the vault). When the underground environment is cited, the term includes exposure to air-outdoor, air-indoor uncontrolled, air, raw water, groundwater, and condensation. This environment is used only for components within the Reactor Building sump suction line guard pipes and isolation valve chambers.	Air, Underground
Waste water	Radioactive, potentially radioactive, or non-radioactive waters that are collected from equipment and floor drains. Waste waters may contain contaminants, including oil and boric acid, as well as originally treated water that is not monitored by a chemistry program.	Waste water
Waste water >60°C (>140°F)	Waste water systems above 60°C [>140°F] exceed the threshold for SS SCC.	Waste water, Waste water >60°C (>140°F)

Note:

1. NUREG-2191 items with environments of “Any” are cited where applicable, and environment equivalences are not listed in this table.
2. Carbonate/bicarbonate environment is not applicable based on pH of soil samples compared to threshold of pH 9.3 specified in Table 4.1 of OPS TTO8, “Stress Corrosion Cracking Study.”

3.1 AGING MANAGEMENT OF REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

3.1.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.1, Reactor Vessel, Internals, and Reactor Coolant System, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Reactor Vessel (Section 2.3.1.1)
- Reactor Vessel Internals (Section 2.3.1.2)
- Reactor Coolant (Section 2.3.1.3)
- Steam Generators (Section 2.3.1.4)

3.1.2 RESULTS

The following table summarizes the results of the aging management review for the Reactor Vessel, Internals, and Reactor Coolant System.

- Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation
- Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation
- Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation
- Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

3.1.2.1 MATERIALS, ENVIRONMENTS, AGING EFFECTS REQUIRING MANAGEMENT AND AGING MANAGEMENT PROGRAMS

3.1.2.1.1 Reactor Vessel

Materials

The materials of construction for the reactor vessel subcomponents are:

- High-strength steel
- Nickel alloy
- Stainless steel
- Steel
- Steel with stainless steel cladding

Environment

The reactor vessel subcomponents are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant
- Reactor coolant and neutron flux

Aging Effects Requiring Management

The following aging effects, associated with the reactor vessel subcomponents, require management:

- Cracking
- Cumulative fatigue damage
- Loss of fracture toughness
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the reactor vessel subcomponents:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Boric Acid Corrosion (B2.1.4)
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Neutron Fluence Monitoring (B3.2)
- One-Time Inspection (B2.1.20)
- Reactor Head Closure Stud Bolting (B2.1.3)
- Reactor Vessel Material Surveillance (B2.1.19)
- Water Chemistry (B2.1.2)

3.1.2.1.2 Reactor Vessel Internals

Materials

The materials of construction for the reactor vessel internals subcomponents are:

- Cast austenitic stainless steel
- Nickel alloy
- Stainless steel
- Stellite

Environment

The reactor vessel internals subcomponents are exposed to the following environments:

- Reactor coolant >250°C (>482°F) and neutron flux
- Reactor coolant and neutron flux

Aging Effects Requiring Management

The following aging effects, associated with the reactor vessel internals subcomponents, require management:

- Changes in dimensions
- Cracking
- Loss of fracture toughness
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the reactor vessel internals subcomponents:

- Flux Thimble Tube Inspection (B2.1.24)
- PWR Vessel Internals (B2.1.7)
- Water Chemistry (B2.1.2)

3.1.2.1.3 Reactor Coolant

Materials

The materials of construction for the reactor coolant system component types are:

- Aluminum
- Cast austenitic stainless steel
- Copper alloy
- Nickel alloy
- Stainless steel
- Steel
- Steel with stainless steel cladding

Environment

The reactor coolant system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Gas
- Lubricating oil
- Reactor coolant
- Reactor coolant >250°C (>482°F)
- Treated borated water
- Treated borated water >60°C (>140°F)
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the reactor coolant system, require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the reactor coolant system component types:

- ASME Code Class 1 Small-Bore Piping (B2.1.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)
- Water Chemistry (B2.1.2)

3.1.2.1.4 Steam Generators

Materials

The materials of construction for the steam generators subcomponents are:

- Nickel alloy
- Stainless steel
- Steel
- Steel with nickel alloy cladding
- Steel with stainless steel cladding

Environment

The steam generators subcomponents are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant
- Steam
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the steam generators subcomponents, require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the steam generators subcomponents:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- One-Time Inspection (B2.1.20)
- Steam Generators (B2.1.10)
- Water Chemistry (B2.1.2)

3.1.2.2 FURTHER EVALUATION OF AGING MANAGEMENT AS RECOMMENDED BY NUREG-2192

NUREG-2192 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the Subsequent License Renewal Application. For the reactor vessel, internals, and reactor coolant system, those evaluations are addressed in the following sections.

3.1.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). These types of TLAAs are addressed separately in Section 4.3, "Metal Fatigue," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Cumulative fatigue damage is an aging effect assessed by a fatigue time-limited aging analysis (TLAA).

[3.1.1-001] – The evaluation of fatigue is a TLAA for high-strength steel reactor vessel closure head stud, nut and washer exposed to air-indoor uncontrolled in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.4, Reactor Vessel and Replacement Reactor Vessel Closure Head.

[3.1.1-002] – The evaluation of fatigue is a TLAA for nickel alloy steam generator components exposed to reactor coolant or steam in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.5, Steam Generators.

[3.1.1-005] – The evaluation of fatigue is a TLAA for steel or stainless steel steam generator components in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.5, Steam Generators.

[3.1.1-008] – The evaluation of fatigue is a TLAA for stainless steel, steel (with nickel alloy or stainless steel cladding) or nickel alloy steam generator components exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.5, Steam Generators.

[3.1.1-009] – The evaluation of fatigue is a TLAA for stainless steel, steel (with stainless steel cladding), or cast austenitic stainless steel reactor coolant pressure boundary components exposed to reactor coolant, reactor coolant >250°C (>482°F), or treated borated water >60°C (>140°F) in the Reactor Vessel, Internals, and Reactor Coolant System, and in Auxiliary Systems, and is discussed in Section 4.3.1, Transient Cycle Projections for 80 years. The evaluation of fatigue is a TLAA for stainless steel reactor coolant system primary loop piping, and is discussed in Section 4.3.3, Non-Class 1 Allowable Stress Analyses, Section 4.3.5, High-Energy Line Break Analysis, and in Section 4.7.3, Leak-Before-Break.

[3.1.1-010] – The evaluation of fatigue is a TLAA for steel (with stainless steel cladding), stainless steel, or nickel alloy reactor vessel components exposed to reactor coolant or reactor coolant and neutron flux in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.4, Reactor Vessel and Replacement Reactor Vessel Closure Head.

[3.1.1-011] – The evaluation of fatigue is a TLAA for steel pump and valve closure bolting exposed to high temperatures and thermal cycles in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2, ASME Code, Section III, Class 1 Fatigue Analyses.

3.1.2.2.2 Loss of Material due to General, Pitting, and Crevice Corrosion

(1) Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR SG upper and lower shell and transition cone exposed to secondary feedwater and steam. The existing program relies on control of water chemistry to mitigate corrosion and inservice inspection (ISI) to detect loss of material. The extent and schedule of the existing SG inspections are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the welds. However, according to NRC Information Notice (IN) 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," the program may not be sufficient to detect pitting and crevice corrosion if general and pitting corrosion of the shell is known to exist. Augmented inspection is recommended to manage this aging effect. Furthermore, this issue is limited to Westinghouse Model 44 and 51 Steam Generators, where a high-stress region exists at the shell to transition cone weld. Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-SLR).

(1) [3.1.1-012] Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. A plant-specific program is recommended for Westinghouse Model 44 and 51 Steam Generators, where a high-stress region exists at the shell to transition cone weld. The steam generators are Westinghouse Model Delta 75, so this issue is not applicable and a plant-specific program is not needed. Loss of material for the steam generator upper and lower shell and transition cone exposed to steam and treated water is managed by the Water Chemistry (B2.1.2) program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program.

(2) Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR steam generator shell assembly exposed to secondary feedwater and steam. The existing program relies on control of secondary water chemistry to mitigate corrosion. However, some applicants have replaced only the bottom part of their recirculating SGs, generating a cut in the middle of the transition cone, and, consequently, a new transition cone closure weld. It is recommended that volumetric examinations be performed in accordance with the requirements of ASME Code, Section XI for upper shell and lower shell-to-transition cones with gross structural discontinuities for managing loss of material due to general, pitting, and crevice corrosion in the welds for Westinghouse Model 44 and 51 SGs, where a high-stress region exists at the shell to transition cone weld.

The new continuous circumferential weld, resulting from cutting the transition cone as discussed above, is a different situation from the SG transition cone welds containing geometric discontinuities. Control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations of stagnant flow conditions. The new transition area weld is a field weld as opposed to having been made in a controlled manufacturing facility, and the surface conditions of the transition weld may result in flow conditions more conducive to initiation of general, pitting, and crevice corrosion than those of the upper and lower transition cone welds. Crediting of the ISI program for the new SG transition cone weld may not be an effective basis for managing loss of material in this weld, as the ISI criteria would only perform a VT-2 visual leakage examination of the weld as part of the system leakage test performed pursuant to ASME Code, Section XI requirements. In addition, ASME Code, Section XI does not require licensees to remove insulation when performing visual examination on nonborated treated water systems. Therefore, the effectiveness of the chemistry control program should be verified to ensure that loss of material due to general, pitting and crevice corrosion is not occurring.

For the new continuous circumferential weld, further evaluation is recommended to verify the effectiveness of the chemistry control program. A one-time inspection at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly, such that the component's intended function will be maintained during the subsequent period of extended operation. Furthermore, this issue is limited to replacement of recirculating SGs with a new transition cone closure weld.

(2) [3.1.1-012] - Loss of material due to general, pitting, and crevice corrosion could result in the steel PWR steam generator shell assembly exposed to secondary feedwater and steam. It is recommended that volumetric examinations be performed in accordance with the requirements of ASME Code, Section XI for upper shell and lower shell-to-transition cones for Westinghouse Model 44 and 51 SGs, where a high-stress region exists at the shell to transition cone weld. The steam generators are Westinghouse Model Delta 75, so this volumetric examination is not needed. Additionally, for situations where a new continuous circumferential weld exists, resulting from cutting the transition cone when only the bottom part of the recirculating steam generators were replaced, it is recommended that a one-time inspection be performed at susceptible locations to determine whether an aging effect is occurring or an aging effect is progressing very slowly, such that the component's intended function will be maintained during the subsequent period of extended operation. Since the steam generators were replaced in their entirety, this one-time inspection is not applicable. Loss of material for the steam generator upper and lower shell and transition cone exposed to steam and treated water is managed by the Water Chemistry (B2.1.2) program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program.

3.1.2.2.3 Loss of Fracture Toughness due to Neutron Irradiation Embrittlement

(1) Neutron irradiation embrittlement is a TLAA to be evaluated for the subsequent period of extended operation for all ferritic materials that have a neutron fluence greater than 10^17 n/cm^2 (E >1 MeV) at the end of the subsequent period of extended operation. Certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.2, Reactor Pressure Vessel Neutron Embrittlement Analysis, of this SRP-SLR.

(1) [3.1.1-013] – Neutron irradiation embrittlement is a TLAA as defined in 10 CFR 54.3 and is evaluated in Section 4.2, Reactor Vessel Neutron Embrittlement Analysis.

(2) Loss of fracture toughness due to neutron irradiation embrittlement could occur in BWR and PWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. A reactor vessel material surveillance program monitors neutron irradiation embrittlement of the reactor vessel. The reactor vessel material surveillance program is either a plant-specific surveillance program or an integrated surveillance program, depending on matters such as the composition of limiting materials and the availability of surveillance capsules.

In accordance with 10 CFR Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. Thus, further NRC staff evaluation is required for a subsequent license renewal (SLR). Specific recommendations for an acceptable AMP are provided in GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance."

A neutron fluence monitoring program may be used to monitor the neutron fluence levels that are used as the time-dependent inputs for the plant's reactor vessel neutron irradiation embrittlement TLAAs. These TLAAs are the subjects of the topics discussed in SRP-SLR Section 3.1.2.2.3.1 and "acceptance criteria" and "review procedure" guidance in SRP SLR Section 4.2. For those applicants that determine it is appropriate to include a neutron fluence monitoring AMP in their SLRAs, the program is to be implemented in conjunction with the applicant's implementation of an AMP that corresponds to GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance." Specific recommendations for an acceptable neutron fluence monitoring AMP are provided in GALL-SLR Report AMP X.M2, "Neutron Fluence Monitoring."'

(2) [3.1.1-014] – Loss of fracture toughness due to neutron irradiation embrittlement could occur in the reactor vessel shell, primary nozzle, and support pad. The Reactor Vessel Material Surveillance (B2.1.19) program and the Neutron Fluence Monitoring (B3.2) program monitor neutron irradiation embrittlement of the reactor vessel.

(3) Reduction in Fracture Toughness is a plant-specific TLAA for Babcock & Wilcox (B&W) reactor internals to be evaluated for the subsequent period of extended operation in accordance with the NRC staff's safety evaluation concerning "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals," B&W Owners Group report number BAW-2248, which is included in BAW-2248A, March 2000. Plant-specific TLAAs are addressed in Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR.

(3) Not applicable. This further evaluation item is applicable to Babcock & Wilcox reactor internals only.

3.1.2.2.4 Cracking due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking

(1) Cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) could occur in stainless steel (SS) and nickel alloy reactor vessel (RV) flange leak detection lines of BWR light-water reactor facilities. The plant specific operating experience (OE) and condition of the RV flange leak detection lines are evaluated to determine if SCC or IGSCC has occurred. The aging effect of cracking in SS and nickel alloy RV flange leak detection lines is not applicable and does not require management if (a) the plant specific OE does not reveal a history of SCC or IGSCC and (b) a one-time inspection demonstrates that the aging effect is not occurring. The applicant documents the results of the plant-specific OE review in the SLRA. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that cracking is not occurring. If cracking has occurred, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking in RV flange leak detection lines.

(1) Not applicable - BWR only.

(2) Cracking due to SCC and IGSCC could occur in SS BWR isolation condenser components exposed to reactor coolant. The existing program relies on control of reactor water chemistry to mitigate SCC and on ASME Code, Section XI ISI to detect cracking. However, the existing program should be augmented to detect cracking due to SCC and IGSCC. An augmented program is recommended to include temperature and radioactivity monitoring of the shell-side water and eddy current testing of tubes to ensure that the component's intended function will be maintained during the subsequent period of extended operation. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

(2) Not applicable - BWR only.

3.1.2.2.5 Crack Growth due to Cyclic Loading

Crack growth due to cyclic loading could occur in reactor pressure vessel (RPV) shell forgings clad with SS using a high-heat-input welding process. Therefore, the current licensing basis (CLB) may include flaw growth evaluations of intergranular separations (i.e., underclad cracks) that have been identified in the RPV to cladding welds for the vessel. The evaluations apply to SA 508 Class 2 RPV forging components where the cladding was deposited and welded to the vessel using a high heat input welding process. Tor CLBs that include these types of evaluations, the evaluations may need to be identified as TLAAs if they are determined to conform to the six criteria for defining TLAAs in 10 CFR 54.3(a). The methodology for evaluating the underclad flaw should be consistent with the flaw evaluation procedure and criterion in the ASME Code, Section XI. See SRP-SLR, Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," for generic guidance for meeting the requirements of 10 CFR 54.21(c).

Not applicable. The reactor vessel shell flange and the primary inlet and outlet nozzle forgings are the reactor vessel components constructed of SA-508 Class 2 material. Applicable welding procedure specifications were reviewed, and it was determined that low-heat input techniques were used during cladding of the reactor vessel SA-508, Class 2 forgings, which would avoid the formation of underclad cracking. While underclad cracking is not a concern for these components at, the PWROG evaluation of reactor vessels that are susceptible to underclad cracking, documented in PWROG-17031-NP-A, "Update for Subsequent License Renewal: WCAP-15338-A, A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants," confirms the structural integrity of the reactor vessel considering the possibility of non-disclosed flaws existing in the cladding-to-base metal interface for 80 years of plant operation.

The reactor vessel head has been replaced with a SA-508, Grade 3, Class 1 forging, and is not susceptible to underclad cracking.

As a result, there is no TLAA for underclad cracking at VCSNS.

3.1.2.2.6 Cracking due to Stress Corrosion Cracking

(1) Cracking due to SCC could occur in PWR SS bottom-mounted instrument guide tubes exposed to reactor coolant. Further evaluation is recommended to ensure that these aging effects are adequately managed. A plant-specific AMP should be evaluated to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

(1) [3.1.1-019] – Cracking due to SCC could occur in PWR stainless steel bottom mounted instrument guide tubes exposed to reactor coolant. Mitigation and monitoring of cracking of the bottom-mounted instrument guide tubes are managed by the Water Chemistry (B2.1.2) program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program respectively. The Water Chemistry (B2.1.2) program provides controls to minimize the presence of contaminants that promote SCC. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program, relies on VT-2 examinations to identify and evaluate the degradation of bottom-mounted instrumentation guide tubes (external to bottom head) to ensure that there is no loss of intended function.

(2) Cracking due to SCC could occur in Class 1 PWR cast austenitic stainless steel (CASS) reactor coolant system piping and piping components exposed to reactor coolant. The existing program relies on control of water chemistry to mitigate SCC; however, SCC could occur in CASS components that do not meet the NUREG—0313, "Technical Report on Material Selection and Process Guidelines for BWR Coolant Pressure Boundary Piping" guidelines with regard to ferrite and carbon content. Further evaluation is recommended of a plant-specific program for these components to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

(2) [3.1.1-020] – Sensitization and IGSCC could occur in CASS components that do not meet the NUREG-0313 guidelines regarding ferrite and carbon content. Class 1 CASS piping and components include the three reactor coolant pump casings which are one-piece castings and 18 cast pipe fittings. All components meet the criterion for greater than or equal to 7.5% ferrite but do not meet the criterion for less than or equal to 0.035% carbon. However, review of NUREG-0313, Revision 2 describes industry experience where IGSCC of CASS components occurred in boiling water reactors (BWRs) primarily due to susceptible CASS components being exposed to BWR water chemistry with high levels of oxygen and other contaminants. NUREG-0313 does not identify IGSCC of CASS components as being problematic in pressurized water reactors (PWRs). This can be attributed to the very tight controls of PWR water chemistry for dissolved oxygen and other aggressive contaminants. Also, there has been no history of cracking in the Class 1 CASS components. As identified in Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6) program, ultrasonic (UT) inspections were performed on the welds attaching the CASS elbows to the reactor vessel inlet nozzle safe ends with no recordable indications identified in the attached CASS piping. Therefore, the Water Chemistry (B2.1.2) program is effective in managing the aging effects of cracking due to SCC in Class 1 RCS CASS piping and piping components and an additional plant specific program to manage aging is not required.

This position is consistent with a similar evaluation which was previously found acceptable by the Staff [Safety Evaluation Report Related to the Subsequent License Renewal of Turkey Point Generating Units 3 and 4, Section 3.1.2.2.6 (ADAMS Accession No. ML19191A057)].

(3) Cracking due to SCC could occur in SS or nickel alloy RV flange leak detection lines of PWR light-water reactor facilities. The plant specific OE and condition of the RV flange leak detection lines are evaluated to determine if SCC has occurred. The aging effect of cracking in SS and nickel alloy RV flange leak detection lines is not applicable and does not require management if: (a) the plant specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring. The applicant documents the results of the plant specific OE review in the SLRA. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that cracking is not occurring. If cracking has occurred, GALL SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking in RV flange leak detection lines.

(3) [3.1.1-139] – Cracking due to SCC could occur in stainless steel or nickel alloy reactor vessel flange leak detection lines of PWR light-water reactor facilities. The reactor vessel flange leakage monitor tube and the vessel flange leakage detection lines are made of stainless steel. A review of plant-specific operating experience did not identify any instances of reactor vessel flange detection line degradation. A one-time inspection will be performed under the One-Time Inspection (B2.1.20) program to demonstrate that cracking is not occurring.

3.1.2.2.7 Cracking due to Cyclic Loading

Cracking due to cyclic loading could occur in steel and SS BWR isolation condenser components exposed to reactor coolant. The existing program relies on ASME Code, Section XI ISI. However, the existing program should be augmented to detect cracking due to cyclic loading. An augmented program is recommended to include temperature and radioactivity monitoring of the shell-side water and eddy current testing of tubes to ensure that the component's intended function will be maintained during the subsequent period of extended operation. Acceptance criteria are described in BTP RLSB 1 (Appendix A.1 of this SRP-SLR).

Not applicable - BWR only.

3.1.2.2.8 Loss of Material due to Erosion

Loss of material due to erosion could occur in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater. Further evaluation is recommended of a plant-specific AMP to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

The steam generators do not have feedwater impingement plates and associated supports. Therefore, this item is not applicable.

3.1.2.2.9 Aging Management of Pressurized Water Reactor Vessel Internals (Applicable to Subsequent License Renewal Periods Only)

Electric Power Research Institute (EPRI) Topical Report (TR)-1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP 227 A)" (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML12017A191 through ML12017A197 and ML12017A199), provides the industry's current aging management recommendations for the reactor vessel internal (RVI) components that are included in the design of a PWR facility. In this report, the EPRI Materials Reliability Program identified that the following aging mechanisms may be applicable to the design of the RVI components in these types of facilities: (a) SCC, (b) irradiation-assisted stress corrosion cracking (IASCC), (c) fatigue, (d) wear, (e) neutron irradiation embrittlement, (f) thermal aging embrittlement, (g) void swelling and irradiation growth, or (h) thermal or irradiation-enhanced stress relaxation or irradiation enhanced creep. The methodology in MRP-227-A was approved by the NRC in a safety evaluation dated December 16, 2011 (ADAMS Accession No. ML11308A770), which includes those plant specific applicant/licensee action items that a licensee or applicant applying the MRP-227-A report would need to address and resolve and apply to its licensing basis.

The EPRI MRP's functionality analysis and failure modes, effects, and criticality analysis bases for grouping Westinghouse-designed, B&W-designed and Combustion Engineering (CE)-designed RVI components into these inspection categories was based on an assessment of aging effects and relevant time-dependent aging parameters through a cumulative 60-year licensing period (i.e., 40 years for the initial operating license period plus an additional 20 years during the initial period of extended operation). The EPRI MRP has not assessed whether operation of Westinghouse-designed, B&W designed and CE designed reactors during an SLR operating period would have any impact on the existing susceptibility rankings and inspection categorizations for the RVI components in these designs, as defined in MRP-227-A or its applicable MRP background documents (e.g., MRP-191 for Westinghouse-designed or CE designed RVI components or MRP-189 for B&W designed components).

As described in GALL-SLR Report AMP XI.M16A, the applicant may use the MRP-227-A based AMP as an initial reference basis for developing and defining the AMP that will be applied to the RVI components for the subsequent period of extended operation. However, to use this alternative basis, GALL-SLR Report AMP XI.M16A recommends that the MRP-227-A based AMP be enhanced to include a gap analysis of the components that are within the scope of the AMP. The gap analysis is a basis for identifying and justifying any potential changes to the MRP-227-A based program that may be necessary to provide reasonable assurance that the effects of age related degradation will be managed during the subsequent period of extended operation. The criteria for the gap analysis are described in GALL-SLR Report AMP XI.M16A.

Alternatively, the PWR SLRA may define a plant-specific AMP for the RVI components to demonstrate that the RVI components will be managed in accordance with the requirements of 10 CFR 54.21(a)(3) during the proposed subsequent period of extended operation. Components to be inspected, parameters monitored, monitoring methods, inspection sample size, frequencies, expansion criteria, and acceptance criteria are justified in the SLRA. The NRC staff will assess the adequacy of the plant-specific AMP against the criteria for the 10 AMP program elements that are defined in Section A.1.2.3 of SRP-SLR Appendix A.1.

[3.1.1-053a] [3.1.1-053b] [3.1.1-053c] [3.1.1-055c] [3.1.1-059a] [3.1.1-059b] [3.1.1-059c] – Electric Power Research Institute (EPRI) Topical Report (TR)-3002017168, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A)” provides the industry’s current aging management recommendations for the reactor vessel internal (RVI) components that are included in the design of a PWR facility. MRP-227, Revision 1-A, incorporated the industry's bases for resolving operating experience and industry lessons learned resulting from component-specific inspections performed since the issuance of MRP-227-A in January 2012. The methodology and guidelines in MRP-227, Revision 1-A, were found acceptable by the NRC, as documented in a staff-issued safety evaluation dated April 25, 2019, and approved for use as documented in the staff’s letters to the EPRI Materials Reliability Program (MRP) dated February 19, 2020 and July 7, 2020.

The approved MRP-227, Revision 1-A, guidelines are based on an assessment of aging effects and relevant time-dependent aging parameters through a cumulative 60-year licensing period (i.e.,40 years for the initial operating license period plus an additional 20 years during the initial period of extended operation). To address an 80-year operating period, the guidelines have been supplemented with a gap analysis that identifies enhancements to the PWR Vessel Internals (B2.1.7) program. The MRP-227, Revision 1-A, Gap Analysis for PWR Vessel Internals Aging Management provides a basis for identifying and justifying any potential changes to the MRP-227, Revision 1-A based program that are necessary to provide reasonable assurance that the effects of age-related degradation will be managed during the subsequent period of extended operation.

The PWR Vessel Internals (B2.1.7) program manages the applicable aging effects for the reactor vessel internal components and the Water Chemistry (B2.1.2) program monitors and controls water environments consistent with industry guidelines to ensure that the reactor coolant water environment is favorable to mitigate SCC and pitting and crevice corrosion in RVI components.

3.1.2.2.10 Loss of Material Due to Wear

(1) Industry OE indicates that loss of material due to wear can occur in PWR control rod drive (CRD) head penetration nozzles made of nickel alloy due to the interactions between the nozzle and the thermal sleeve centering pads of the nozzle (see Ref. 29). The CRD head penetration nozzles are also called control rod drive mechanism (CRDM) nozzles or CRDM head adapter tubes. The applicant should perform a further evaluation to confirm the adequacy of a plant specific AMP or analysis (with any necessary inspections) for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP. Alternatively, the applicant may perform an analysis with any necessary inspections to confirm that loss of material due to wear does not affect the intended function(s) of these CRD head penetration nozzles, consistent with the current licensing basis (CLB).

(1) [3.1.1-116] – Loss of material due to wear can occur in PWR control rod drive head penetration nozzles made of nickel alloy due to the interaction between the nozzle and the thermal sleeve centering pads of the nozzle. The head penetration nozzles are also called control rod drive mechanism (CRDM) head adapter tubes. The reactor vessel closure head has been replaced. The new design has eliminated the CRDM head adapter tube thermal sleeves, which eliminates the potential for nozzle wear at this location. Therefore, a plant-specific program is not needed. The control rod drive mechanism nozzle is addressed by item 3.1.1-088.

(2) Industry OE indicates that loss of material due to wear can occur in the SS thermal sleeves of PWR CRD head penetration nozzles due to the interactions between the nozzle and the thermal sleeve (e.g. where the thermal sleeve exits from the head penetration nozzle inside the reactor vessel as describe in Ref. 30). Therefore, the applicant should perform a further evaluation to confirm the adequacy of a plant specific AMP for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP.

(2) Loss of material due to wear can occur in the SS thermal sleeves of PWR CRD head penetration nozzles (CRDM head adapter tubes) due to the interactions between the nozzle and the thermal sleeve. The reactor vessel closure head has been replaced. The new design has eliminated the CRDM head adapter tube thermal sleeves, which eliminates the potential for thermal sleeve wear. Therefore, a plant-specific program is not needed. The thermal sleeve function of guiding the rod drive movement is now accomplished by the guide funnel, which is addressed by item 3.1.1-088.

3.1.2.2.11 Cracking due to Primary Water Stress Corrosion Cracking

(1) Foreign OE in steam generators with a design similar to that of Westinghouse steam generators (particularly Model 51) has identified cracks due to primary water stress corrosion cracking (PWSCC) in steam generator (SG) divider plate assemblies fabricated of Alloy 600 and/or the associated Alloy 600 weld materials, even with proper primary water chemistry. Cracks have been detected in the stub runner with depths typically about 0.08 inches (EPRI 3002002850).

All but one of these instances of cracking has been detected in divider plate assemblies that are approximately 1.3 inches in thickness. For the cracks in the 1.3-inch thick divider plate assemblies, the cracks tend to be parallel to the divider-plate-to-stub-runner weld (i.e., run horizontally in parallel to the lower surface of the tubesheet). For the one instance of cracking in a divider plate assembly with a thickness greater than 1.3 inches, the cracking occurred in a divider plate assembly with a thickness of approximately 2.4 inches near manufacturing marks on the upper end of the stub runner used for locating tubesheet holes. These flaws were estimated to be approximately 0.08-inch deep.

Although these instances indicate that the water chemistry program may not be sufficient to manage cracking due to PWSCC in SG divider plate assemblies, analyses by the industry indicate that PWSCC in the divider plate assembly does not pose a structural integrity concern for other steam generator components (e.g., tubesheet and tube-to-tubesheet welds) and does not adversely affect other safety analyses (e.g., analyses supporting tube plugging and repairs, tube repair criteria, and design basis accidents). In addition, the industry analyses indicate that flaws in the divider plate assembly will not adversely affect the heat transfer function (as a result of bypass flow) during normal forced flow operation, during natural circulation conditions (assessed in the analyses of various design basis accidents), or in the event of a loss-of-coolant accident (LOCA).

Furthermore, additional industry analyses indicate that PWSCC in the divider plate assembly is unlikely to adversely impact adjacent items, such as the tubesheet cladding, tube-to-tubesheet welds, and channel head. Therefore,

•For units with divider plate assemblies fabricated of Alloy 690 and Alloy 690 type weld materials, a plant-specific AMP is not necessary.

•For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the analyses performed by the industry (EPRI 3002002850) are applicable and bounding for the unit, a plant-specific AMP is not necessary.

•For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the industry analyses (EPRI 3002002850) are not bounding for the applicant's unit, a plant-specific AMP is necessary or a rationale is necessary for why such a program is not needed. A plant-specific AMP (one beyond the primary water chemistry and the steam generator programs) may include a one time inspection that is capable of detecting cracking to verify the effectiveness of the water chemistry and steam generator programs and the absence of PWSCC in the divider plate assemblies.

The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and general visual inspections of the channel head interior surfaces (included as part of the steam generator program). The GALL-SLR Report recommends further evaluation for a plant-specific AMP to confirm the effectiveness of the primary water chemistry and steam generator programs as described in this section. Acceptance criteria for a plant-specific AMP are described in BTP RLSB-1 (Appendix A.1 of this SRP SLR). In place of a plant-specific AMP, the applicant may provide a rationale to justify why a plant-specific AMP is not necessary.

(1) [3.1.1-025] – Foreign OE in steam generators with a design similar to that of Westinghouse steam generators (particularly Model 51) has identified cracks due to primary water stress corrosion cracking (PWSCC) in steam generator (SG) divider plate assemblies fabricated of Alloy 600 and/or the associated Alloy 600 weld materials, even with proper primary water chemistry. The steam generator divider plate assemblies and associated welds are fabricated of Alloy 690 materials. Therefore, a plant-specific AMP is not necessary.

Cracking of the steam generator channel head divider plate is managed by the Steam Generators (B2.1.10) program and the Water Chemistry (B2.1.2) program.

(2) Cracking due to PWSCC could occur in SG nickel alloy tube-to-tubesheet welds exposed to reactor coolant. The acceptance criteria for this review are:

•For units with Alloy 600 SG tubes for which an alternate repair criterion such as C, F*, H*, or W* has been permanently approved for both the hot- and cold-leg side of the steam generator, the weld is no longer part of the reactor coolant pressure boundary and a plant specific AMP is not necessary;*

•For units with Alloy 600 steam generator tubes, if there is no permanently approved alternate repair criteria such as C, F*, H*, or W*, or permanent approval applies to only either the hot- or cold-leg side of the steam generator, a plant specific AMP is necessary;*

•For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 690 type material, a plant-specific AMP is not necessary;

•For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 600 type material, a plant-specific AMP is necessary unless the applicant confirms that the industry's analyses for tube-to-tubesheet weld cracking (e.g., chromium content for the tube-to-tubesheet welds is approximately 22 percent and the tubesheet primary face is in compression as discussed in EPRI 3002002850) are applicable and bounding for the unit, and the applicant will perform general visual inspections of the tubesheet region looking for evidence of cracking (e.g., rust stains on the tubesheet cladding) as part of the steam generator program. In lieu of a plant-specific AMP, the applicant may provide a rationale for why a plant-specific AMP is not necessary.

The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and visual inspections of the steam generator head interior surfaces. Along with the primary water chemistry and steam generator programs, a plant-specific AMP should be evaluated to confirm the effectiveness of the primary water chemistry and steam generator programs in certain circumstances. A plant-specific AMP may include a one-time inspection that is capable of detecting cracking to confirm the absence of PWSCC in the tube-to-tubesheet welds. Acceptance criteria for a plant-specific AMP are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR). In place of a plant specific AMP, the applicant may provide a rationale to justify why a plant-specific AMP is not necessary.

(2) [3.1.1-025] – Cracking due to PWSCC could occur in steam generator nickel alloy tube-to-tubesheet welds exposed to reactor coolant. The steam generators have thermally treated Alloy 690 tubes and the tubesheets are clad using Alloy 82 (ERNiCr-3) and/or 182 (ENiCrFe-3) type material.

The analysis performed by the industry (EPRI 3002002850) evaluated PWSCC in nickel alloy tube-to-tubesheet welds for the Westinghouse Model 51 steam generator, which was determined to be the most limiting steam generator model.In a letter to the industry dated October 10, 2016, EPRI provided a checklist to determine whether this analysis bounds an applicant's steam generators. This checklist was completed and documents that the analysis is applicable and bounding for the steam generators; and visual inspections of the tubesheet region looking for evidence of cracking are performed as part of the Steam Generators (B2.1.10) program. Therefore, a plant-specific AMP is not necessary.

Cracking of the steam generator tube-to-tubesheet welds exposed to reactor coolant is managed by the Steam Generators (B2.1.10) program and the Water Chemistry (B2.1.2) program.

3.1.2.2.12 Cracking Due to Irradiation-Assisted Stress Corrosion Cracking

GALL-SLR Report AMP XI.M9, "BWR Vessel Internals," manages aging degradation of nickel alloy and SS, including associated welds, which are used in BWR vessel internal components. When exposed to the BWR vessel environment, these materials can experience cracking due to IASCC. The existing Boiling Water Reactor Vessel and Internals Project (BWRVIP) examination guidelines are mainly based on aging evaluation of BWR vessel internals for operation up to 60 years. However, increases in neutron fluence during the SLR term may need to be assessed for supplemental inspections of BWR vessel internals to adequately manage cracking due to IASCC. Therefore, the applicant should perform an evaluation to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines. If the applicant determines that supplemental inspections are not necessary, the applicant should provide adequate technical justification for the determination. If supplemental inspections are determined necessary for BWR vessel internals, the applicant identifies the components to be inspected and performs supplemental inspections to adequately manage IASCC. In addition, the applicant should confirm the adequacy of any necessary supplemental inspections and enhancements to the BWR Vessel Internals Program.

Not applicable - BWR only.

3.1.2.2.13 Loss of Fracture Toughness Due to Neutron Irradiation or Thermal Aging Embrittlement

GALL-SLR Report AMP XI.M9 manages aging degradation of nickel alloy and SS, including associated welds, which are used in BWR vessel internal components. When exposed to the BWR vessel environment, these materials can experience loss of fracture toughness due to neutron irradiation embrittlement. In addition, CASS, precipitation-hardened (PH) martensitic SS (e.g., 15-5 and 17-4 PH steel) and martensitic SS (e.g., 403, 410, 431 steel) can experience loss of fracture toughness due to neutron irradiation or thermal aging embrittlement.

The existing BWRVIP examination guidelines are mainly based on aging evaluation of BWR vessel internals for operation up to 60 years. Increases in neutron fluence and thermal embrittlement during the SLR term may need to be assessed for supplemental inspections of BWR vessel internals to adequately manage loss of fracture toughness due to neutron irradiation or thermal aging embrittlement. Therefore, the applicant should perform an evaluation to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines. If the applicant determines that supplemental inspections are not necessary, the applicant should provide adequate technical justification for the determination. If supplemental inspections are determined necessary for BWR vessel internals, the applicant should identify the components to be inspected and perform supplemental inspections to adequately manage loss of fracture toughness. In addition, the applicant should confirm the adequacy of any necessary supplemental inspections and enhancements to the BWR Vessel Internals Program.

Not applicable - BWR only.

3.1.2.2.14 Loss of Preload Due to Thermal or Irradiation-Enhanced Stress Relaxation

GALL-SLR Report AMP XI.M9 manages loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR core plate rim holddown bolts. The issue is applicable to BWR designed light water reactors that employ rim holddown bolts as the means for protecting the reactor's core plate from the consequences of lateral movement. The potential for such movement, if left unmanaged, could impact the ability of the reactor to be brought to a safe shutdown condition during an anticipated transient occurrence or during a postulated design basis accident or seismic event. This issue is not applicable to BWR reactor designs that use wedges as the means of precluding lateral movement of the core plate because the wedges are fixed in place and are not subject to this type of aging effect and mechanism combination.

GALL-SLR Report AMP XI.M9 indicates that the inspections in the BWRVIP topical report, "BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines (BWRVIP-25)," are used to manage loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR designs with core plate rim holddown bolts. However, in previous license renewal applications (LRAs), some applicants have identified that the inspection bases for managing loss of preload in BWRVIP-25 may not be capable of gaining access to the rim holddown bolts or are not sufficient to detect loss of preload on the components. For applicants that have identified this issue in their past LRAs, the applicants either committed to modifying the plant design to install wedges in the core plate designs or to submit an inspection plan, with a supporting core plate rim holddown bolt preload analysis for NRC approval at least 2 years prior to entering into the initial period of extended operation for the facility.

If an existing NRC-approved analysis for the bolts exists in the CLB and conforms to the definition of a TLAA, the applicant should identify the analysis as a TLAA for the SLRA and demonstrate how the analysis is acceptable in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii). Otherwise, if a new analysis will be performed to support an updated augmented inspection basis for the bolts for the subsequent period of extended operation, the NRC staff recommends that a license renewal commitment be placed in the FSAR Supplement for the applicant to submit both the inspection plan and the supporting loss of preload analysis to the NRC staff for approval at least 2 years prior to entering into the subsequent period of extended operation for the facility. If loss of preload in the bolts is managed with an AMP that correlates to GALL-SLR Report AMP XI.M9, the inspection basis in the applicable BWRVIP report is reviewed for continued validity, or else augmented as appropriate.

Not applicable - BWR only.

3.1.2.2.15 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG—1557; (b) plant specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and cracking due to SCC (SS only) are identified as applicable aging effects. GALL SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

Not applicable. There are no in-scope steel piping or piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System.

3.1.2.2.16 Loss of Material Due to Pitting and Crevice Corrosion

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if: (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping and piping components exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage loss of material due to pitting or crevice corrosion. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

[3.1.1-136] – Loss of material due to pitting and crevice corrosion could occur in stainless steel and nickel alloy piping, piping components, and tanks exposed to any air environment. A review of plant-specific operating experience did not identify loss of material due to pitting or crevice corrosion for stainless steel or nickel alloy components in any air environment (air-indoor uncontrolled, air-outdoor, or condensation). A one-time inspection will be performed under the One-Time Inspection (B2.1.20) program to demonstrate that loss of material is not occurring for stainless steel and nickel alloy components of the Reactor Vessel, Internals, and Reactor Coolant System exposed to air-indoor uncontrolled.

3.1.2.2.17 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.1.2.2.18 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

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Results Tables: Reactor Vessel, Internals, and Reactor Coolant System

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-001	Steel reactor vessel closure flange assembly components exposed to air-indoor uncontrolled	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel reactor vessel closure flange assembly components exposed to air-indoor uncontrolled is a TLAA. See further evaluation in Section 3.1.2.2.1.
3.1.1-002	Nickel alloy tubes and sleeves exposed to reactor coolant, secondary feedwater/steam	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of nickel alloy components exposed to reactor coolant or steam is a TLAA. See further evaluation in Section 3.1.2.2.1.
3.1.1-003	Stainless steel, nickel alloy reactor vessel internal components exposed to reactor coolant, neutron flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Not applicable. As documented in NUREG-1787, "Safety Evaluation Report Related to the License Renewal of the Virgil C. Summer Nuclear Station", Section 4.3.2, the code of record for the reactor vessel internals is ASME Section III, Class 2, which does not specify a fatigue analysis. Monitoring of stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux is addressed by items 3.1.1-053a, 3.1.1-053b, 3.1.1-053c, 3.1.1-054, 3.1.1-055c, 3.1.1-059a, 3.1.1-059b, 3.1.1-059c, and 3.1.1-087. The associated NUREG-2191 aging items are not used.
3.1.1-004	Steel pressure vessel support skirt and attachment welds	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Not applicable. There are no in-scope steel reactor pressure vessel support skirt and attachment welds in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-005	Steel, stainless steel, steel (with stainless steel or nickel alloy cladding) steam generator components, pressurizer relief tank components, piping components, bolting	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel or stainless steel components is a TLAA. See further evaluation in Section 3.1.2.2.1.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-006	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy reactor coolant pressure boundary components: piping, piping components; other pressure retaining components exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Not applicable - BWR only.
3.1.1-007	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy reactor vessel components: nozzles; penetrations; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Not applicable - BWR only.
3.1.1-008	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy steam generator components exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of stainless steel, steel (with nickel alloy or stainless steel cladding) or nickel alloy steam generator components exposed to reactor coolant is a TLAA. See further evaluation in Section 3.1.2.2.1.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-009	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy reactor coolant pressure boundary piping, piping components; other pressure retaining components exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of stainless steel or steel (with stainless steel cladding) reactor coolant pressure boundary components or other pressure components exposed to reactor coolant, reactor coolant >250°C (>482°F), or treated borated water >60°C (>140°F) is a TLAA. In addition to Reactor Vessel, Internals, And Reactor Coolant System, components in the Auxiliary Systems (chemical and volume control) are aligned to this item. See further evaluation in Section 3.1.2.2.1.
3.1.1-010	Steel (with or without nickel alloy or stainless steel cladding), stainless steel, or nickel alloy reactor vessel components: nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel with stainless steel cladding, stainless steel, or nickel alloy reactor vessel components exposed to reactor coolant or reactor coolant and neutron flux is a TLAA. See further evaluation in Section 3.1.2.2.1.
3.1.1-011	Steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	'Consistent with NUREG-2191. Cumulative fatigue damage of steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles is a TLAA. See further evaluation in Section 3.1.2.2.1.
3.1.1-012	Steel steam generator components: upper and lower shells, transition cone; new transition cone closure weld exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	Yes (SRP-SLR Sections 3.1.2.2.2.1 and 3.1.2.2.2.2)	Consistent with NUREG-2191. A plant-specific program is not needed for the shell to transition cone weld. See further evaluation in Section 3.1.2.2.2.1 and 3.1.2.2.2.2.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-013	Steel (with or without stainless steel or nickel alloy cladding) reactor vessel beltline shell, nozzle, and weld components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, SRP-SLR Section 4.2 Reactor Pressure Vessel Neutron Embrittlement	Yes (SRP-SLR Section 3.1.2.2.3.1)	Consistent with NUREG-2191. Loss of fracture toughness of steel (with stainless steel cladding) reactor vessel components exposed to reactor coolant and neutron flux is a TLAA. See further evaluation in Section 3.1.2.2.3.1.
3.1.1-014	Steel (with or without cladding) reactor vessel beltline shell, nozzle, and weld components; exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	AMP XI.M31, Reactor Vessel Material Surveillance, and X.M2, Neutron Fluence Monitoring	Yes (SRP-SLR Section 3.1.2.2.3.2)	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Neutron Fluence Monitoring (B3.2) program implementation. See further evaluation in Section 3.1.2.2.3.2.
3.1.1-015	Stainless steel Babcock & Wilcox (including CASS, martensitic SS, and PH SS) and nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux	Reduction in fracture toughness due to neutron irradiation	TLAA, SRP-SLR Section 4.7 Other Plant-Specific TLAAs	Yes (SRP-SLR Section 3.1.2.2.3.3)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-016	Stainless steel or nickel alloy reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled, reactor coolant leakage	Cracking due to SCC, IGSCC	AMP XI.M32, One-Time Inspection, or AMP XI.M36, External Surfaces Monitoring of Mechanical Components	Yes (SRP-SLR Section 3.1.2.2.4.1)	Not applicable - BWR only.
3.1.1-017	Stainless steel isolation condenser components exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	Yes (SRP-SLR Section 3.1.2.2.4.2)	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-018	Reactor vessel shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process exposed to reactor coolant	Crack growth due to cyclic loading	TLAA, SRP-SLR Section 4.7 Other Plant-Specific TLAAs	Yes (SRP-SLR Section 3.1.2.2.5)	Not applicable. There are no reactor vessel components fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process exposed to reactor coolant. See further evaluation in Section 3.1.2.2.5. The associated NUREG-2191 aging items are not used.
3.1.1-019	Stainless steel reactor vessel bottom-mounted instrument guide tubes (external to reactor vessel) exposed to reactor coolant	Cracking due to SCC	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.6.1)	Consistent with NUREG-2191. Cracking of stainless steel reactor vessel bottom-mounted instrument guide tubes (external to reactor vessel) exposed to reactor coolant is managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program and the Water Chemistry (B2.1.2) program. See further evaluation in Section 3.1.2.2.6.1.
3.1.1-020	Cast austenitic stainless steel Class 1 piping, piping components exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, Water Chemistry and plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.6.2)	Consistent with NUREG-2191, without a plant-specific program. A plant-specific program is not needed for the cast austenitic stainless steel Class 1 piping and components. See further evaluation in Section 3.1.2.2.6.2.
3.1.1-021	Steel and stainless steel isolation condenser components exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Yes (SRP-SLR Section 3.1.2.2.7)	Not applicable - BWR only.
3.1.1-022	Steel steam generator feedwater impingement plate and support exposed to secondary feedwater	Loss of material due to erosion	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.8)	Not applicable. There is no in-scope steel steam generator feedwater impingement plate and support exposed to secondary feedwater in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-025	Steel (with nickel alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M2, Water Chemistry, and AMP XI.M19, Steam Generators. In addition, a plant-specific program is to be evaluated.	Yes (SRP-SLR Sections 3.1.2.2.11.1 and 3.1.2.2.11.2)	Consistent with NUREG-2191. A plant-specific program is not needed for the divider plate or for the tube-to-tubesheet weld. See further evaluation in Section 3.1.2.2.11.1 and 3.1.2.2.11.2.
3.1.1-028	Westinghouse-specific Existing Programs components: Stainless steel, nickel alloy, and X-750 control rod guide tube support pins (split pins) exposed to reactor coolant and neutron flux	Loss of material due to wear; cracking due to SCC, IASCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. The stainless steel control rod guide tube support pins (split pins) are “No additional measures” components and are addressed by row 3.1.1-055c. The associated NUREG-2191 items are not used.
3.1.1-029	Nickel alloy core shroud and core plate access hole cover (welded covers) exposed to reactor coolant	Cracking due to SCC, IGSCC, IASCC	AMP XI.M9, BWR Vessel Internals, and AMP XI.M2, Water Chemistry	Yes (SRP-SLR Section 3.1.2.2.12)	Not applicable - BWR only.
3.1.1-030	Stainless steel, nickel alloy penetration: drain line exposed to reactor coolant	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry (SCC, IGSCC mechanisms only)	No	Not applicable - BWR only.
3.1.1-031	Steel and stainless steel isolation condenser components exposed to reactor coolant	Loss of material due to general (steel only), pitting, crevice corrosion, wear	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-033	Stainless steel, steel with stainless steel cladding Class 1 reactor coolant pressure boundary components exposed to reactor coolant	Cracking due to SCC	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191 and a different aging management program is credited for some components. The Steam Generators (B2.1.10) program will manage cracking of the steam generator channel head and channel head drain tube instead of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program. In addition to Reactor Vessel, Internals, And Reactor Coolant System, components in the Engineered Safety Features (residual heat removal and safety injection) and Auxiliary Systems (chemical and volume control) are aligned to this row.
3.1.1-034	Stainless steel, steel with stainless steel cladding pressurizer relief tank (tank shell and heads, flanges, nozzles) exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Not applicable. There are no in-scope stainless steel, steel with stainless steel cladding pressurizer relief tank (tank shell and heads, flanges, nozzles) exposed to treated borated water >60°C (>140°F) in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-035	Stainless steel, steel with stainless steel cladding reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
3.1.1-036	Steel, stainless steel pressurizer integral support exposed to any environment	Cracking due to cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
3.1.1-037	Steel reactor vessel flange	Loss of material due to wear	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-038	Cast austenitic stainless steel Class 1 valve bodies and bonnets exposed to reactor coolant >250 °C (>482 °F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable. There are no in-scope cast austenitic stainless steel Class 1 valve bodies and bonnets exposed to reactor coolant >250 °C (>482 °F) in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-039	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy Class 1 piping, fittings and branch connections < NPS 4 exposed to reactor coolant	Cracking due to SCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), IGSCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), or thermal, mechanical, or vibratory loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, AMP XI.M2, Water Chemistry, and XI.M35, ASME Code Class 1 Small-Bore Piping	No	Consistent with NUREG-2191. In addition to Reactor Vessel, Internals, And Reactor Coolant System, components in the Engineered Safety Features (safety-injection) and Auxiliary Systems (chemical and volume control) are aligned to this item.
3.1.1-040	Steel with stainless steel or nickel alloy cladding; or stainless steel pressurizer components exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
3.1.1-040a	Nickel alloy core support pads; core guide lugs exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191.
3.1.1-041	Nickel alloy core shroud and core plate access hole cover (mechanical covers) exposed to reactor coolant	Cracking due to SCC, IGSCC, IASCC	AMP XI.M9, BWR Vessel Internals, and AMP XI.M2, Water Chemistry	Yes (SRP-SLR Section 3.1.2.2.12)	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-042	Steel with stainless steel or nickel alloy cladding; stainless steel primary side components; steam generator upper and lower heads, and tube sheet welds; pressurizer components exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191.
3.1.1-043	Stainless steel and nickel alloy reactor vessel internals exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.1.1-044	Steel steam generator secondary manway and handhole cover seating surfaces exposed to treated water, steam	Loss of material due to erosion	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
3.1.1-045	Nickel alloy, steel with nickel alloy cladding reactor coolant pressure boundary components exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD, and AMP XI.M2, Water Chemistry, and, for nickel-alloy, AMP XI.M11B, Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in RCPB Components (PWRs Only)	No	Consistent with NUREG-2191.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-046	Stainless steel, nickel alloy control rod drive head penetration pressure housings, reactor vessel nozzles, nozzle safe ends and welds exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD, and AMP XI.M2, Water Chemistry, and, for nickel-alloy, AMP XI.M11B, Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced corrosion in RCPB Components (PWRs Only)	No	Consistent with NUREG-2191.
3.1.1-047	Stainless steel, nickel alloy control rod drive head penetration pressure housing exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191.
3.1.1-048	Steel external surfaces: reactor vessel top head, reactor vessel bottom head, reactor coolant pressure boundary piping or components adjacent to dissimilar metal (Alloy 82/182) welds exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, Boric Acid Corrosion, and AMP XI.M11B, Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid- Induced Corrosion in RCPB Components (PWRs Only)	No	Consistent with NUREG-2191.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-049	Steel reactor vessel, piping, piping components in the reactor coolant pressure boundary of PWRs, and applicable exterior attachments, or steel steam generators in PWRs: external surfaces or closure bolting exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, Boric Acid Corrosion	No	Consistent with NUREG-2191.
3.1.1-050	Cast austenitic stainless steel Class 1 piping, piping components (including pump casings and control rod drive pressure housings) exposed to reactor coolant >250 °F (>482 °C)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	No	Consistent with NUREG-2191.
3.1.1-051a	Stainless steel, nickel alloy Babcock & Wilcox reactor internal Primary components exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-051b	Stainless steel, nickel alloy Babcock & Wilcox reactor internal Expansion components exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, fatigue, overload	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-052a	Stainless steel, nickel alloy Combustion Engineering reactor internal Primary components exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-052b	Stainless steel, nickel alloy Combustion Engineering reactor internal Expansion components exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-052c	Stainless steel, nickel alloy Combustion Engineering reactor internal Existing Programs components exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-053a	Stainless steel, nickel alloy Westinghouse reactor internal Primary components exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.
3.1.1-053b	Stainless steel Westinghouse reactor internal Expansion components exposed to reactor coolant and neutron flux	Cracking due to SCC, IASCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.
3.1.1-053c	Stainless steel, nickel alloy, or stellite Westinghouse reactor internal Existing Programs components exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-054	Stainless steel Westinghouse-design bottom mounted instrument system flux thimble tubes (with or without chrome plating) exposed to reactor coolant and neutron flux	Loss of material due to wear	AMP XI.M37, Flux Thimble Tube Inspection	No	Consistent with NUREG-2191.
3.1.1-055a	Stainless steel, nickel alloy Babcock and Wilcox reactor internal No Additional Measures components exposed to reactor coolant, neutron flux	No additional aging management for reactor internal No Additional Measures components unless required by ASME Section XI, Examination Category B-N-3 or relevant operating experience exists	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-055b	Stainless steel, nickel alloy Combustion Engineering reactor internal No Additional Measures components exposed to reactor coolant, neutron flux	No additional aging management for reactor internal No Additional Measures components unless required by ASME Section XI, Examination Category B-N-3 or relevant operating experience exists	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-055c	Stainless steel, nickel alloy Westinghouse reactor internal No Additional Measures components exposed to reactor coolant, neutron flux	No additional aging management for reactor internal No Additional Measures components unless required by ASME Section XI, Examination Category B-N-3 or relevant operating experience exists	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.
3.1.1-056a	Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Combustion Engineering reactor internal Primary components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-056b	Stainless steel (SS, including CASS, PH SS or martensitic SS) Combustion Engineering Expansion reactor internal components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-056c	Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Combustion Engineering reactor internal Existing Programs components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-058a	Stainless steel (SS, including CASS, PH SS or martensitic SS), nickel alloy Babcock & Wilcox reactor internal Primary components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; or changes in dimensions due to void swelling or distortion; or loss of preload due to wear; or loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-058b	Stainless steel (SS, including CASS, PH SS or martensitic SS), nickel alloy Babcock & Wilcox reactor internal Expansion components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; or changes in dimensions due to void swelling, or distortion; or loss of preload due to thermal and irradiation-enhanced stress relaxation, or creep; or loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. VCSNS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-059a	Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Westinghouse reactor internal Primary components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-059b	Stainless steel (SS, including CASS, PH SS or martensitic SS) Westinghouse reactor internal Expansion components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-059c	Stainless steel (SS, including CASS, PH SS or martensitic SS), nickel alloy, or stellite Westinghouse reactor internal Existing Programs components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.
3.1.1-060	Steel piping, piping components exposed to reactor coolant	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Not applicable - BWR only.
3.1.1-061	Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Consistent with NUREG-2191.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-062	High-strength steel, stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled	Cracking due to SCC	AMP XI.M18, Bolting Integrity	No	Not applicable. High-strength steel closure bolting (closure head stud, nut, and washer) is addressed by row 3.1.1-092. The associated NUREG-2191 aging items are not used.
3.1.1-063	Steel or stainless steel closure bolting exposed to air – indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion, wear	AMP XI.M18, Bolting Integrity	No	Not applicable - BWR only.
3.1.1-064	Steel or stainless steel closure bolting exposed to air – indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion, wear	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.1.1-065	Stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled	Loss of material due to wear	AMP XI.M18, Bolting Integrity	No	Not applicable. There is no in-scope stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-066	Steel, stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.1.1-067	Steel or stainless steel closure bolting exposed to air – indoor uncontrolled (external)	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-068	Nickel alloy steam generator tubes exposed to secondary feedwater or steam	Changes in dimension (denting) due to corrosion of carbon steel tube support plate	AMP XI.M19, Steam Generators, and AMP XI.M2, Water Chemistry	No	Not applicable. There are no nickel alloy tube support plates in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-069	Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam	Cracking due to outer diameter SCC, intergranular attack	AMP XI.M19, Steam Generators, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191.
3.1.1-070	Nickel alloy steam generator tubes, repair sleeves, and tube plugs exposed to reactor coolant	Cracking due to primary water SCC	AMP XI.M19, Steam Generators, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191.
3.1.1-071	Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti-vibration bars exposed to secondary feedwater or steam	Cracking due to SCC or other mechanism(s); loss of material due general (steel only), pitting, crevice corrosion	AMP XI.M19, Steam Generators, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191 and a different aging management program is credited for some components. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used instead of the Steam Generators (B2.1.10) program to manage cracking and loss of material for the auxiliary feedwater nozzle thermal sleeve and feedwater nozzle thermal sleeve.
3.1.1-072	Steel steam generator tube support plate, tube bundle wrapper, supports and mounting hardware exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion, erosion, ligament cracking due to corrosion	AMP XI.M19, Steam Generators, and AMP XI.M2, Water Chemistry (corrosion based aging effects and mechanisms only)	No	Consistent with NUREG-2191.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-073	Nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater or steam	Loss of material due to wastage, pitting corrosion	AMP XI.M19, Steam Generators, and AMP XI.M2, Water Chemistry	No	Not applicable. There are no in-scope nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater or steam in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-074	Steel steam generator upper assembly and separators including feedwater inlet ring and support exposed to secondary feedwater or steam	Wall thinning due to flow-accelerated corrosion	AMP XI.M19, Steam Generators, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191.
3.1.1-075	Steel steam generator tube support lattice bars exposed to secondary feedwater or steam	Wall thinning due to flow-accelerated corrosion, general corrosion	AMP XI.M19, Steam Generators, and AMP XI.M2, Water Chemistry	No	Not applicable. There are no in-scope steel steam generator tube support lattice bars exposed to secondary feedwater or steam in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-076	Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti-vibration bars exposed to secondary feedwater or steam	Loss of material due to wear, fretting	AMP XI.M19, Steam Generators	No	Consistent with NUREG-2191 and a different aging management program is credited for some components. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used instead of the Steam Generators (B2.1.10) program to manage loss of material for the auxiliary feedwater nozzle thermal sleeve and feedwater nozzle thermal sleeve.
3.1.1-077	Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam	Loss of material due to wear, fretting	AMP XI.M19, Steam Generators	No	Consistent with NUREG-2191, with a TLAA evaluation included. Wear of steam generator tubes at tube support plates is a TLAA, evaluated in Section 4.7.4, Steam Generator Tube Wear Evaluation.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-078	Nickel alloy steam generator components such as, secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater or steam	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection, or AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD.	No	Not applicable. The steam generators are recirculating steam generators, not once-through. The associated NUREG-2191 aging items are not used.
3.1.1-079	Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor coolant pressure boundary components exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.1.1-080	Stainless steel or steel with stainless steel cladding pressurizer relief tank: tank shell and heads, flanges, nozzles (none-ASME Section XI components) exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope stainless steel or steel with stainless steel cladding pressurizer relief tank: tank shell and heads, flanges, nozzles (non-ASME Section XI components) exposed to treated borated water >60°C (>140°F) in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-081	Stainless steel pressurizer spray head exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. There is no in-scope stainless steel pressurizer spray head exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-082	Nickel alloy pressurizer spray head exposed to reactor coolant	Cracking due to SCC, primary water SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. No Reactor Vessel, Internals, and Reactor Coolant System components are aligned to this item. Only heat exchanger components in Auxiliary Systems (nuclear sampling) are aligned to this item.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-083	Steel steam generator shell assembly exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. Loss of material of the steel steam generator shell assembly exposed to secondary feedwater or steam is addressed by item 3.1.1-012. The associated NUREG-2191 aging items are not used.
3.1.1-084	Steel top head enclosure (without cladding): top head, top head nozzles (vent, top head spray, RCIC, spare) exposed to reactor coolant	Loss of material due to general, pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.1.1-085	Stainless steel, nickel alloy, and steel with nickel alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.1.1-086	Stainless steel steam generator primary side divider plate exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, Water Chemistry	No	Not applicable. There is no in-scope stainless steel steam generator primary side divider plate exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-087	Stainless steel, nickel alloy PWR reactor internal components exposed to reactor coolant, neutron flux	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-088	Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor coolant pressure boundary components exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191. In addition to Reactor Vessel, Internals, And Reactor Coolant System, components in the Engineered Safety Features (residual heat removal and safety-injection) and Auxiliary Systems (chemical and volume control) are aligned to this item.
3.1.1-089	Steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191.
3.1.1-090	Copper alloy piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191.
3.1.1-091	Steel (including high-strength steel) reactor vessel closure flange assembly components (including flanges, nut, studs, and washers) exposed to air-indoor uncontrolled	Cracking due to SCC; loss of material due to general, pitting, crevice corrosion, wear	AMP XI.M3, Reactor Head Closure Stud Bolting	No	Not applicable - BWR only.
3.1.1-092	Steel (including high-strength steel) reactor vessel closure flange assembly components (including flanges, nut, studs, and washers) exposed to air-indoor uncontrolled	Cracking due to SCC, IGSCC; loss of material due to general, pitting, crevice corrosion, wear	AMP XI.M3, Reactor Head Closure Stud Bolting	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Reactor Head Closure Stud Bolting (B2.1.3) program implementation.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-093	Copper alloy >15% Zn or >8% Al piping, piping components exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Not applicable. There are no in-scope copper alloy >15% Zn or >8% Al piping, piping components exposed to closed-cycle cooling water, treated water in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-094	Stainless steel and nickel alloy vessel shell attachment welds exposed to reactor coolant	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M4, BWR Vessel ID Attachment Welds, and AMP XI.M2, Water Chemistry (SCC, IGSCC mechanisms only)	No	Not applicable - BWR only.
3.1.1-095	Steel (with or without stainless steel or nickel alloy cladding) feedwater nozzles exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable - BWR only.
3.1.1-096	Steel (with or without stainless steel cladding) control rod drive return line nozzles and their nozzle-to-vessel welds exposed to reactor coolant in BWR-3, BWR-4, BWR-5, and BWR-6 designs	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-097	Stainless steel and nickel alloy piping, piping components greater than or equal to 4 NPS; nozzle safe ends and associated welds; control rod drive return line nozzle cap and associated cap-to-nozzle weld or cap-to-safe end weld in BWR-3, BWR 4, BWR 5, and BWR-6 designs	Cracking due to SCC, IGSCC	AMP XI.M7, BWR Stress Corrosion Cracking, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.1.1-098	Stainless steel, nickel alloy penetrations: instrumentation and standby liquid control exposed to reactor coolant	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M8, BWR Penetrations, and AMP XI.M2, Water Chemistry (SCC, IGSCC mechanisms only)	No	Not applicable - BWR only.
3.1.1-099	Stainless steel (including cast austenitic stainless steel; PH martensitic stainless steel; martensitic stainless steel); nickel alloy (including X-750 alloy) reactor internal components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement	AMP XI.M9, BWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.13)	Not applicable - BWR only.
3.1.1-100	Stainless steel reactor vessel internals components (jet pump wedge surface) exposed to reactor coolant	Loss of material due to wear	AMP XI.M9, BWR Vessel Internals	No	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-101	Stainless steel steam dryers exposed to reactor coolant	Cracking due to flow-induced vibration, SCC, IGSCC; loss of material due to wear	AMP XI.M9, BWR Vessel Internals	No	Not applicable - BWR only.
3.1.1-102	Stainless steel fuel supports and control rod drive assemblies control rod drive housing exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M9, BWR Vessel Internals, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.1.1-103	Stainless steel, nickel alloy reactor internal components exposed to reactor coolant and neutron flux	Cracking due to SCC, IGSCC, IASCC	AMP XI.M9, BWR Vessel Internals, and AMP XI.M2, Water Chemistry	Yes (SRP-SLR Section 3.1.2.2.12)	Not applicable - BWR only.
3.1.1-104	Nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux	Cracking due to IGSCC	AMP XI.M9, BWR Vessel Internals, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.1.1-105	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.1.2.2.15)	Not applicable. There are no in-scope steel piping, piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-106	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. Boric acid corrosion is not an aging effect requiring management for nickel alloy. The associated NUREG-2191 aging items are not used.
3.1.1-107	Stainless steel piping, piping components exposed to gas, air with borated water leakage	None	None	No	Consistent with NUREG-2191.
3.1.1-110	Metallic piping, piping components exposed to reactor coolant	Wall thinning due to erosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-111	Nickel alloy steam generator tubes exposed to secondary feedwater or steam	Reduction of heat transfer due to fouling	AMP XI.M2, Water Chemistry, and AMP XI.M19, Steam Generators	No	Consistent with NUREG-2191.
3.1.1-113	Steel reactor vessel external attachments exposed to indoor, uncontrolled air	Loss of material due to general, pitting, crevice corrosion, wear	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable - BWR only.
3.1.1-114	Reactor coolant system components defined as ASME Section XI Code Class components (ASME Code Class 1 reactor coolant pressure boundary components, reactor vessel interior attachments, or core support structure components; or ASME Class 2 or 3 components - including ASME defined appurtenances, component supports, and associated pressure boundary welds, or components subject to plant-specific equivalent classifications for these ASME code classes)	Cracking due to SCC, IGSCC, PWSCC, IASCC (SCC mechanisms for stainless steel, nickel alloy components only), fatigue or cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, or wear	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry (water chemistry-related or corrosion-related aging effect mechanisms only)	No	Not applicable. Cracking and loss of material of reactor coolant system components defined as ASME Section XI Code Class components (ASME Code Class 1 reactor coolant pressure boundary components or core support structure components, or ASME Class 2 or 3 components - including ASME defined appurtenances, component supports, and associated pressure boundary welds, or components subject to plant-specific equivalent classifications for these ASME code classes) is addressed by rows 3.1.1-020, 3.1.1-033, 3.1.1-035, 3.1.1-036, 3.1.1-037, 3.1.1-039, 3.1.1-042, 3.1.1-045, 3.1.1-088, and 3.1.1-116. The associated NUREG-2191 aging items are not used.
3.1.1-115	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.1.2.2.15)	Not applicable. There are no in-scope stainless steel piping, piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-116	Nickel alloy control rod drive penetration nozzles exposed to reactor coolant	Loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.10.1)	Not applicable. There are no in-scope nickel alloy control rod drive penetration nozzles exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System that are susceptible to loss of material due to wear. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.1.2.2.10.1.
3.1.1-117	Stainless steel, nickel alloy control rod drive penetration nozzle thermal sleeves exposed to reactor coolant	Loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.10.2)	Not applicable. There are no in-scope stainless steel, nickel alloy control rod drive penetration nozzle thermal sleeves exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.1.2.2.10.2.
3.1.1-118	Stainless steel, nickel alloy PWR reactor vessel internal components or LRA/SLRA-specified reactor vessel internal component exposed to reactor coolant, neutron flux	Cracking due to SCC, IASCC, cyclic loading, fatigue	Plant-specific aging management program or AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (SCC and IASCC only), with an adjusted site-specific or component-specific aging management basis for a specified reactor vessel internal component	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. Cracking of stainless steel and nickel alloy PWR reactor vessel internal components exposed to reactor coolant and neutron flux is addressed by items 3.1.1-053a, 3.1.1-053b and 3.1.1-053c. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-119	Stainless steel, nickel alloy, stellite PWR reactor vessel internal components or LRA/SLRA-specified reactor vessel internal component exposed to reactor coolant, neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement or thermal aging embrittlement; changes in dimensions due to void swelling or distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation or creep; loss of material due to wear	Plant-specific aging management program or AMP XI.M16A, PWR Vessel Internals, with an adjusted site-specific or component-specific aging management basis for a specified reactor vessel internal component	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. Loss of fracture toughness, changes in dimensions, loss of preload, and loss of material of stainless steel, nickel alloy, or stellite PWR reactor vessel internal components is addressed by rows 3.1.1-059a, 3.1.1-059b, and 3.1.1-059c. The associated NUREG-2191 items are not used.
3.1.1-120	Stainless steel core plate rim holddown bolts exposed to reactor coolant and neutron flux	Loss of preload due to thermal or irradiation-enhanced stress relaxation	AMP XI.M9, BWR Vessel Internals, and TLAA SRP-SLR 4.7 Other Plant-Specific TLAAs [if an analysis is performed as part of the aging management basis and conforms to the definition of a TLAA in 10 CFR 54.3(a)]	Yes (SRP-SLR Section 3.1.2.2.14)	Not applicable - BWR only.
3.1.1-121	Stainless steel jet pump assembly holddown beam bolts exposed to reactor coolant and neutron flux	Loss of preload due to thermal or irradiation-enhanced stress relaxation	AMP XI.M9, BWR Vessel Internals	No	Not applicable - BWR only.
3.1.1-124	Steel piping, piping components exposed to air-indoor uncontrolled, air-outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-125	Nickel alloy steam generator tubes at support plate locations exposed to secondary feedwater or steam	Cracking due to flow-induced vibration, high-cycle fatigue	AMP XI.M19, Steam Generators	No	Consistent with NUREG-2191.
3.1.1-127	Steel (with stainless steel or nickel alloy cladding) steam generator heads and tubesheets exposed to reactor coolant	Loss of material due to boric acid corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M19, Steam Generators	No	Consistent with NUREG-2191 and a different aging management program is credited for some components. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will manage loss of material of the steel with stainless steel cladding steam generator primary inlet and outlet nozzle, and the stainless steel primary inlet and outlet nozzle safe ends, exposed to reactor coolant, instead of the Steam Generators (B2.1.10) program.
3.1.1-128	Stainless steel, nickel alloy nozzles safe ends and welds: high pressure core spray; low pressure core spray; recirculating water, low pressure coolant injection or RHR injection mode exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M7, BWR Stress Corrosion Cracking, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-129	Steel and stainless steel piping, piping components exposed to reactor coolant: welded connections between the re-routed control rod drive return line and the inlet piping system that delivers return line flow to the reactor pressure vessel exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable - BWR only.
3.1.1-133	Steel components exposed to treated water	Long-term loss of material due to general corrosion	AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.1.1-134	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There is no in-scope non-metallic thermal insulation exposed to air or condensation in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-136	Stainless steel, nickel alloy piping, piping components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.1.2.2.16)	Consistent with NUREG-2191. Loss of material of stainless steel or nickel alloy components exposed to air - indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.1.2.2.16.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-137	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Not applicable. There are no in-scope copper alloy piping, piping components exposed to air, condensation, or gas in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-139	Stainless steel, nickel alloy reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled, reactor coolant leakage	Cracking due to SCC	AMP XI.M32, One-Time Inspection, or AMP XI.M36, External Surfaces Monitoring of Mechanical Components	Yes (SRP-SLR Section 3.1.2.2.6.3)	Consistent with NUREG-2191. Cracking of the stainless steel reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.1.2.2.6.3.

Results Tables: Reactor Vessel, Internals, and Reactor Coolant System AMR Results

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bottom head dome	PB	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.RP-379	3.1.1-048	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-379	3.1.1-048	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	C
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Bottom mounted instrumentation (guide tube)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-154	3.1.1-019	E, 1
					Water Chemistry (B2.1.2)	IV.A2.RP-154	3.1.1-019	E, 1
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Bottom mounted instrumentation (nozzle and weld)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-59	3.1.1-045	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-59	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.A2.RP-59	3.1.1-045	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Closure head (core exit thermocouple nozzle)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-186	3.1.1-045	C
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-186	3.1.1-045	C
					Water Chemistry (B2.1.2)	IV.A2.RP-186	3.1.1-045	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
						IV.A2.RP-28	3.1.1-088	A
Closure head (dome and flange)	PB	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.RP-379	3.1.1-048	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-379	3.1.1-048	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	C
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Closure head (instrument port head adaptor)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-186	3.1.1-045	C
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-186	3.1.1-045	C
					Water Chemistry (B2.1.2)	IV.A2.RP-186	3.1.1-045	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
						IV.A2.RP-28	3.1.1-088	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	C
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Closure head (lifting lug)	SS	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
Closure head (stud, nut, and washer)	PB	High-strength steel	(E) Air – indoor uncontrolled	Cracking	Reactor Head Closure Stud Bolting (B2.1.3)	IV.A2.RP-52	3.1.1-092	B
				Cumulative fatigue damage	TLAA	IV.A2.RP-54	3.1.1-001	A
				Loss of material	Reactor Head Closure Stud Bolting (B2.1.3)	IV.A2.RP-53	3.1.1-092	B
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Closure head (vent and level instrumentation nozzle)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-186	3.1.1-045	C
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-186	3.1.1-045	C
					Water Chemistry (B2.1.2)	IV.A2.RP-186	3.1.1-045	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
						IV.A2.RP-28	3.1.1-088	A
Control rod drive mechanism (extension tube)	PB	Stainless steel	(E) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Control rod drive mechanism (guide funnel)	PB	Stainless steel	(E) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Control rod drive mechanism (head adapter and weld)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-186	3.1.1-045	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-186	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.A2.RP-186	3.1.1-045	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	C
						IV.A2.RP-28	3.1.1-088	A
Control rod drive mechanism (latch housing)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Control rod drive mechanism (nozzle, j-groove weld)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-186	3.1.1-045	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-186	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.A2.RP-186	3.1.1-045	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Control rod drive mechanism (rod travel housing)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Core support pad	SS	Nickel alloy	(E) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-57	3.1.1-040a	A
					Water Chemistry (B2.1.2)	IV.A2.RP-57	3.1.1-040a	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Primary nozzle and support pad	PB;SS	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
			(I) Reactor coolant and neutron flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	A
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of fracture toughness	TLAA	IV.A2.R-84	3.1.1-013	A
					Neutron Fluence Monitoring (B3.2)	IV.A2.RP-229	3.1.1-014	B
					Reactor Vessel Material Surveillance (B2.1.19)	IV.A2.RP-229	3.1.1-014	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Primary nozzle safe end	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	A
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Primary nozzle weld	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-234	3.1.1-046	A
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Refueling seal ledge	SS	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
Seal table	SS	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Seal table (fitting)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-217	3.1.1-033	C
					Water Chemistry (B2.1.2)	IV.C2.R-217	3.1.1-033	C
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	C
Ventilation shroud support ring	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
Vessel flange and core support ledge	PB	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	C
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.R-87	3.1.1-037	A
					Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Vessel flange leakage monitor tube	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	C
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Vessel shell (upper, intermediate, lower)	PB	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
			(I) Reactor coolant and neutron flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	C
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of fracture toughness	TLAA	IV.A2.R-84	3.1.1-013	A
					Neutron Fluence Monitoring (B3.2)	IV.A2.RP-229	3.1.1-014	B
					Reactor Vessel Material Surveillance (B2.1.19)	IV.A2.RP-229	3.1.1-014	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Plant-Specific Notes:

1. The plant-specific aging management programs used to manage cracking of stainless steel bottom mounted instrumentation guide tubes are the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program and the Water Chemistry (B2.1.2) program.

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Alignment and interfacing components (clevis bearing wear surface)	SS	Stellite	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-399	3.1.1-053c	A
					Water Chemistry (B2.1.2)	IV.B2.RP-399	3.1.1-053c	A
				Loss of material; loss of preload; changes in dimension	PWR Vessel Internals (B2.1.7)	IV.B2.RP-285	3.1.1-059c	C, 6
Alignment and interfacing components (clevis insert bolt)	SS	Nickel alloy	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-399	3.1.1-053c	A
					Water Chemistry (B2.1.2)	IV.B2.RP-399	3.1.1-053c	A
				Loss of material; loss of preload; changes in dimension	PWR Vessel Internals (B2.1.7)	IV.B2.RP-285	3.1.1-059c	A, 6
Alignment and interfacing components (internals hold-down spring)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of preload; changes in dimensions; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-300	3.1.1-059a	A, 2
Alignment and interfacing components (upper core plate alignment pin)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-299	3.1.1-059c	A
		Stellite	(E) Reactor coolant and neutron flux	Loss of material; loss of preload; changes in dimension	PWR Vessel Internals (B2.1.7)	IV.B2.RP-285	3.1.1-059c	C, 6
Alignment and interfacing components (upper core plate insert)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-299	3.1.1-059c	C
Baffle and former assembly (baffle edge bolt, bolting lock device)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-275	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-275	3.1.1-053a	A
				Loss of fracture toughness; changes in dimensions; loss of preload; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-354	3.1.1-059a	A, 2

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Baffle and former assembly (baffle plate)	FD;SS	Stainless steel	(E) Reactor coolant and neutron flux	Changes in dimensions; loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270	3.1.1-059a	A, 3
				Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270a	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-270a	3.1.1-053a	A
Baffle and former assembly (baffle-former bolt)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-271	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-271	3.1.1-053a	A
				Loss of fracture toughness; changes in dimensions; loss of preload; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-272	3.1.1-059a	A, 2
Baffle and former assembly (barrel-former bolt)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-273	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-273	3.1.1-053b	A
				Loss of fracture toughness; changes in dimensions; loss of preload; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-274	3.1.1-059b	A, 2
Baffle and former assembly (former plate)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Changes in dimensions; loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270	3.1.1-059a	A, 3
				Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270a	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-270a	3.1.1-053a	A
Bottom mounted instrumentation (column body)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-293	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-293	3.1.1-053b	A
				Loss of fracture toughness; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-292	3.1.1-059b	A, 4
Bottom mounted instrumentation (column cruciform)	SS	CASS	(E) Reactor coolant >250°C (>482°F) and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-293	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-293	3.1.1-053b	A
				Loss of fracture toughness; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-292	3.1.1-059b	A, 4

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Control rod guide tube assembly and flow downcomer (C-tube and sheath)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	C
Control rod guide tube assembly and flow downcomer (guide plate (card))	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	A
Control rod guide tube assembly and flow downcomer (lower flange weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-298	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-298	3.1.1-053a	A
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-297	3.1.1-059a	A
Control rod guide tube assembly and flow downcomer (remaining lower flange weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-298a	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-298a	3.1.1-053b	A
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-297a	3.1.1-059b	A
Core barrel assembly (core barrel flange)	FD;SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-345	3.1.1-059c	A
Core barrel assembly (lower flange weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-280	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-280	3.1.1-053b	A
Core barrel assembly (lower girth weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-387	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-387	3.1.1-053a	A
				Loss of fracture toughness; changes in dimension	PWR Vessel Internals (B2.1.7)	IV.B2.RP-388	3.1.1-059a	A, 5

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Core barrel assembly (middle & lower axial weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-387a	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-387a	3.1.1-053b	A
				Loss of fracture toughness; changes in dimension	PWR Vessel Internals (B2.1.7)	IV.B2.RP-388a	3.1.1-059b	A, 5
Core barrel assembly (upper axial weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-280	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-280	3.1.1-053b	A
Core barrel assembly (upper flange weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-276	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-276	3.1.1-053a	A
Core barrel assembly (upper girth weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-280	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-280	3.1.1-053b	A
Flux thimble (tube)	PB;SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	Flux Thimble Tube Inspection (B2.1.24)	IV.B2.RP-284	3.1.1-054	A
Lower internals (lower core plate)	FD;SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-289	3.1.1-053c	A
					Water Chemistry (B2.1.2)	IV.B2.RP-289	3.1.1-053c	A
				Loss of fracture toughness; loss of material; changes in dimension	PWR Vessel Internals (B2.1.7)	IV.B2.RP-288	3.1.1-059c	A, 5
Lower internals (lower support forging)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-291a	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-291a	3.1.1-053b	A
Lower internals (radial key wear surface)	SS	Stellite	(E) Reactor coolant and neutron flux	Loss of material; loss of preload; changes in dimension	PWR Vessel Internals (B2.1.7)	IV.B2.RP-285	3.1.1-059c	C, 6
Lower support column assembly (column body)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-294	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-294	3.1.1-053b	A
				Loss of fracture toughness; changes in dimension	PWR Vessel Internals (B2.1.7)	IV.B2.RP-295	3.1.1-059b	A, 5

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Lower support column assembly (column bolt)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-286	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-286	3.1.1-053b	A
				Loss of fracture toughness; loss of preload; changes in dimension; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-287	3.1.1-059b	A, 2
No additional measures components	EN;SP;SS	CASS	(E) Reactor coolant >250°C (>482°F) and neutron flux	None	PWR Vessel Internals (B2.1.7)	IV.B2.RP-265	3.1.1-055c	A, 1
		Nickel alloy	(E) Reactor coolant and neutron flux	None	PWR Vessel Internals (B2.1.7)	IV.B2.RP-265	3.1.1-055c	A, 1
		Stainless steel	(E) Reactor coolant and neutron flux	None	PWR Vessel Internals (B2.1.7)	IV.B2.RP-265	3.1.1-055c	A, 1
Reactor vessel internal components	EN;FD;SS	Nickel alloy	(E) Reactor coolant and neutron flux	Loss of material	Water Chemistry (B2.1.2)	IV.B2.RP-24	3.1.1-087	A
		Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	Water Chemistry (B2.1.2)	IV.B2.RP-24	3.1.1-087	A
Upper internals (upper core plate)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-291b	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-291b	3.1.1-053b	A
				Loss of material; loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-290b	3.1.1-059b	A, 4
Upper support plate assembly (upper support ring or skirt)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-346	3.1.1-053c	A
					Water Chemistry (B2.1.2)	IV.B2.RP-346	3.1.1-053c	A

Table 3.1.2-2 Plant-Specific Notes:

1. No additional measures components include the following: Control rod guide tube assembly and flow downcomer (anti-rotation studs and nuts, bolts, enclosure pins, guide tube enclosures, intermediate flanges, guide tube support pins, housing plates, lock bars, cover plate, cover plate cap screws, cover plate locking caps and tie straps, support pin nuts, water flow slot ligaments), Mixing devices, Upper internals (upper core plate insert bolts, locking devices and dowel pins), Upper instrumentation conduit and supports (bolting; brackets, clamps, terminal blocks, and conduit strap; conduit seal assembly - body, tubesheet, tubesheet weld; conduit seal assembly tube, conduit, flange base, locking cap, support tube), Upper support column assemblies (adapters, bolts, base, body, extension tube, flanges, lock keys, nuts), Upper support plate assembly (upper support plate, deep beam ribs

and stiffeners, locking device), Baffle and former assembly (former dowel pins), Bottom mounted instrumentation (bolts, collars, extension bars and tubes, locking devices, nuts), Core barrel assembly (upflow conversion plug body and mandrel, outlet nozzle), Flux thimble (tube plugs), Head cooling spray nozzle, Irradiation specimen guides (guides, guide bolts, lock caps, specimen plugs and dowel pins), Lower core plate (manway bolts, locking devices), Lower support column (nuts, sleeves, bolt locking devices), Neutron panel/thermal shield (bolts, locking devices, neutron panels), Radial support keys (bolts, locks, keys), Secondary core support assembly (base plate, bolts, energy absorber, guide post, housing, lock keys, upper and lower tie plates), Alignment and interfacing components (clevis inserts, dowels, and locking devices; head and vessel alignment pin bolts, pins and lock cups; replacement reactor vessel head extension tubes). Additionally, the Upper and Lower fuel alignment pins are considered to be in this category since the Gap Analysis identifies that there are no applicable aging effects for them.

2. Changes in dimensions and loss of material are not applicable aging effects for the baffle edge bolt and bolting lock device, baffle-former bolt, barrel-former bolt, internals hold-down spring, and lower support column bolt
3. Loss of fracture toughness is not an applicable aging effect for the baffle plate and former plate.
4. Loss of material is not an applicable aging effect for the bottom mounted instrumentation column body and column cruciform, and upper core plate.
5. Changes in dimensions is not an applicable aging effect for the core barrel assembly lower girth weld and middle & lower axial weld, lower core plate, and lower support column body).
6. Loss of preload and changes in dimension are not applicable aging effects for the upper core plate alignment pin, radial key wear surface, clevis insert bolt, and clevis bearing wear surface.

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	IV.C2.RP-44	3.1.1-011	A
				Loss of material	Bolting Integrity (B2.1.9)	IV.C2.RP-166	3.1.1-064	A
				Loss of preload	Bolting Integrity (B2.1.9)	IV.C2.R-12	3.1.1-066	A
		Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	IV.C2.RP-44	3.1.1-011	A
				Loss of material	Bolting Integrity (B2.1.9)	IV.C2.RP-166	3.1.1-064	A
				Loss of preload	Bolting Integrity (B2.1.9)	IV.C2.R-12	3.1.1-066	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.RP-167	3.1.1-049	A
Drip pan (RCP oil collection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Flame arrestor	FB	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.E.E-444b	3.2.1-101	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.EP-114b	3.2.1-042	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.E.E-444b	3.2.1-101	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.EP-114b	3.2.1-042	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
Flexible hose	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Heat exchanger (RCP motor lower bearing cooler - tube)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-222	3.1.1-090	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.A.EP-100	3.2.1-033	A
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	V.A.EP-76	3.2.1-050	C
					One-Time Inspection (B2.1.20)	V.A.EP-76	3.2.1-050	C
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	V.A.EP-78	3.2.1-051	A
					One-Time Inspection (B2.1.20)	V.A.EP-78	3.2.1-051	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (RCP motor oil cooler - channel)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-221	3.1.1-089	C
Heat exchanger (RCP motor oil cooler - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	V.A.E-473	3.2.1-130	A
					One-Time Inspection (B2.1.20)	V.A.E-473	3.2.1-130	A
Heat exchanger (RCP motor oil cooler - tube)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-222	3.1.1-090	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.A.EP-100	3.2.1-033	A
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	V.A.EP-76	3.2.1-050	C
					One-Time Inspection (B2.1.20)	V.A.EP-76	3.2.1-050	C
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	V.A.EP-78	3.2.1-051	A
					One-Time Inspection (B2.1.20)	V.A.EP-78	3.2.1-051	A
Heat exchanger (RCP motor oil cooler - tubesheet)	PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-222	3.1.1-090	C
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	V.A.EP-76	3.2.1-050	C
					One-Time Inspection (B2.1.20)	V.A.EP-76	3.2.1-050	C
Heat exchanger (thermal barrier - tube)	HT;PB	Stainless steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.A.EP-93	3.2.1-031	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.A.EP-96	3.2.1-033	A
			(E) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	C
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	C
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	C

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Hydraulic isolator	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.A.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.A.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Piping (reactor vessel flange leakage detection line)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	IV.A2.R-74a	3.1.1-139	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	C

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Gas	None	None	IV.E.RP-07	3.1.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.A.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.A.E-12	3.2.1-020	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	A
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A
Piping, piping components (Class 1 <NPS 4)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Code Class 1 Small-Bore Piping (B2.1.22)	IV.C2.RP-235	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-235	3.1.1-039	A
					Water Chemistry (B2.1.2)	IV.C2.RP-235	3.1.1-039	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	V.D1.E-407	3.2.1-065	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components (Class 1)	PB	CASS	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant >250°C (>482°F)	Cracking	Water Chemistry (B2.1.2)	IV.C2.R-05	3.1.1-020	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-56	3.1.1-035	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of fracture toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)	IV.C2.R-52	3.1.1-050	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-56	3.1.1-035	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	V.D1.E-407	3.2.1-065	A
Pressurizer (heater well coupling)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer (instrument and sample tube and coupling)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (lower and upper heads)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (manway cover bolting)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	IV.C2.RP-166	3.1.1-064	A
				Loss of preload	Bolting Integrity (B2.1.9)	IV.C2.R-12	3.1.1-066	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.RP-167	3.1.1-049	A
Pressurizer (manway cover)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer (nozzle and manway forgings)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (nozzle safe end)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (nozzle weld overlay)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
Pressurizer (nozzle weld)	PB	Stainless steel	(E) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (seismic lug)	SS	Steel	(E) Air – indoor uncontrolled	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-19	3.1.1-036	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer (shell)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (spray and surge nozzle thermal sleeves)	LTC	Stainless steel	(E) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (support skirt)	SS	Steel	(E) Air – indoor uncontrolled	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-19	3.1.1-036	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (reactor coolant)	PB	CASS	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant >250°C (>482°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-09	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.R-09	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of fracture toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)	IV.C2.R-52	3.1.1-050	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Rupture disc	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Gas	None	None	IV.E.RP-07	3.1.1-107	A
Tank (pressurizer relief)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Tank (RCP oil collection enclosure)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (RCP oil collection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Gas	None	None	IV.E.RP-07	3.1.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.A.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.A.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Plant-Specific Notes: None

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Anti-vibration bar	SS	Stainless steel	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	A
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Anti-vibration bar retaining ring and bar	SS	Nickel alloy	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	A
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Auxiliary feedwater internal spray pipe	PB;SP	Nickel alloy	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
			(I) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
Auxiliary feedwater nozzle	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Treated water	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	C
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	C
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	IV.D1.R-37	3.1.1-061	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Auxiliary feedwater nozzle thermal sleeve	LTC	Nickel alloy	(E) Treated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-384	3.1.1-071	E, 1
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-226	3.1.1-071	E, 1
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-225	3.1.1-076	E, 1
Blowdown header	FD	Nickel alloy	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
			(I) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
Channel head	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-232	3.1.1-033	E, 2
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	C
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.R-436	3.1.1-127	A
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	A
Channel head divider plate	FD	Nickel alloy	(E) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-367	3.1.1-025	A
					Water Chemistry (B2.1.2)	IV.D1.RP-367	3.1.1-025	A
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Channel head drain tube	PB	Stainless steel	(I) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-232	3.1.1-033	E, 2
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	C
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.R-436	3.1.1-127	C
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	C
Feedwater distribution ring	FD	Steel	(E) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	C
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	C
			(I) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	C
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	C
				Wall thinning	Steam Generators (B2.1.10)	IV.D1.RP-49	3.1.1-074	A
					Water Chemistry (B2.1.2)	IV.D1.RP-49	3.1.1-074	A
Feedwater distribution ring safe end	FD	Nickel alloy	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
			(I) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
Feedwater distribution ring spray nozzle	SP	Nickel alloy	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
			(I) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Feedwater nozzle	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Treated water	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	C
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	C
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	IV.D1.R-37	3.1.1-061	A
Feedwater nozzle thermal sleeve	LTC	Nickel alloy	(E) Treated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-384	3.1.1-071	E, 1
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-226	3.1.1-071	E, 1
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-225	3.1.1-076	E, 1
Moisture separator assembly	FD	Steel	(E) Steam	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	C
				Wall thinning	Steam Generators (B2.1.10)	IV.D1.RP-49	3.1.1-074	A
					Water Chemistry (B2.1.2)	IV.D1.RP-49	3.1.1-074	A
			(I) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	C
				Wall thinning	Steam Generators (B2.1.10)	IV.D1.RP-49	3.1.1-074	A
					Water Chemistry (B2.1.2)	IV.D1.RP-49	3.1.1-074	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Moisture separator column assembly	FD	Nickel alloy	(E) Steam	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	C
			(I) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	C
Primary inlet and outlet nozzle	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.R-436	3.1.1-127	E, 3
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	C
Primary inlet and outlet nozzle safe end	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.R-436	3.1.1-127	E, 3
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	C

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Primary inlet and outlet nozzle weld	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-159	3.1.1-045	C
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.C2.RP-159	3.1.1-045	C
					Water Chemistry (B2.1.2)	IV.C2.RP-159	3.1.1-045	C
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Primary manway	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.R-436	3.1.1-127	C
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	C
Primary manway cover	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
Primary manway cover bolting	PB	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	IV.C2.R-18	3.1.1-005	A
				Loss of material	Bolting Integrity (B2.1.9)	IV.D1.RP-166	3.1.1-064	A
				Loss of preload	Bolting Integrity (B2.1.9)	IV.D1.RP-46	3.1.1-067	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Primary manway cover insert	PB	Stainless steel	(E) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.R-436	3.1.1-127	C
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	C
Secondary manway	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Steam	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	A
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.R-31	3.1.1-044	A
Secondary manway cover	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Steam	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	C
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	C
Secondary manway cover bolting	PB	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	IV.C2.R-18	3.1.1-005	A
				Loss of material	Bolting Integrity (B2.1.9)	IV.D1.RP-166	3.1.1-064	A
				Loss of preload	Bolting Integrity (B2.1.9)	IV.D1.RP-46	3.1.1-067	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Secondary side shell (lower shell, upper shell, transition cone, closure weld)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	A
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	A
Secondary side shell (penetration cover bolting)	PB	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	IV.C2.R-18	3.1.1-005	A
				Loss of material	Bolting Integrity (B2.1.9)	IV.D1.RP-166	3.1.1-064	A
				Loss of preload	Bolting Integrity (B2.1.9)	IV.D1.RP-46	3.1.1-067	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
Secondary side shell (penetration cover)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	C
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	C
Secondary side shell (penetration)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Steam	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	A
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	A
			(I) Treated water	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	A
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Secondary side shell (upper head and steam outlet nozzle)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Steam	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	A
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	IV.D1.R-37	3.1.1-061	A
Steam flow limiter	RF	Nickel alloy	(I) Steam	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Cumulative fatigue damage	TLAA	IV.D1.R-46	3.1.1-002	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
Support pad	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
Tube	HT;PB	Nickel alloy	(I) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.R-44	3.1.1-070	A
					Water Chemistry (B2.1.2)	IV.D1.R-44	3.1.1-070	A
				Cumulative fatigue damage	TLAA	IV.D1.R-46	3.1.1-002	A
			(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.R-47	3.1.1-069	A
					Water Chemistry (B2.1.2)	IV.D1.R-47	3.1.1-069	A
					Steam Generators (B2.1.10)	IV.D1.R-437	3.1.1-125	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-233	3.1.1-077	A
					TLAA	IV.D1.RP-233	3.1.1-077	E, 4
				Reduction of heat transfer	Steam Generators (B2.1.10)	IV.D1.R-407	3.1.1-111	A
					Water Chemistry (B2.1.2)	IV.D1.R-407	3.1.1-111	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tube bundle stay rod and spacer	SS	Steel	(E) Treated water	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	A
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Tube bundle support and baffle plate	FD;SS	Stainless steel	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	A
				Cumulative fatigue damage	TLAA	IV.C2.R-18	3.1.1-005	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	A
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Tube bundle wrapper	FD;SS	Steel	(E) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	A
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	A
Tube plug	PB	Nickel alloy	(E) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.R-40	3.1.1-070	A
					Water Chemistry (B2.1.2)	IV.D1.R-40	3.1.1-070	A
				Cumulative fatigue damage	TLAA	IV.D1.R-46	3.1.1-002	C
Tubesheet	PB	Steel with nickel alloy cladding	(I) Reactor coolant	Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.R-436	3.1.1-127	A
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	A
			(E) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	C
Tube-to-tubesheet weld	PB	Nickel alloy	(E) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-385	3.1.1-025	A
					Water Chemistry (B2.1.2)	IV.D1.RP-385	3.1.1-025	A
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A

Table 3.1.2-4 Plant-Specific Notes:

1. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used instead of the Steam Generators (B2.1.10) program to manage cracking and loss of material for the feedwater nozzle thermal sleeve and auxiliary feedwater nozzle thermal sleeve.
2. The Steam Generators (B2.1.10) program is used instead of the ASME Section XI Inservice Inspection, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program to manage cracking due to stress corrosion cracking for the channel head stainless steel cladding and the channel head drain tube.
3. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used instead of the Steam Generators (B2.1.10) program to manage loss of material due to boric acid corrosion for the primary inlet and outlet nozzle and safe end.
4. Wear of steam generator tubes at the tube support plates is a plant-specific TLAA, evaluated in Steam Generator Tube Wear Evaluation (4.7.4).

Tables 3.1.2-1 through 3.1.2-4 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

F. Material not in NUREG-2191 for this component.

G. Environment not in NUREG-2191 for this component and material.

H. Aging effect not in NUREG-2191 for this component, material and environment combination.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

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3.2 AGING MANAGEMENT OF ENGINEERED SAFETY FEATURES

3.2.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.2, Engineered Safety Features, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Reactor Building Spray (Section 2.3.2.1)
- Refueling Water (Section 2.3.2.2)
- Residual Heat Removal (Section 2.3.2.3)
- Safety Injection (Section 2.3.2.4)

3.2.2 RESULTS

The following tables summarize the results of the aging management review for Engineered Safety Features Systems.

- Table 3.2.2-1, Engineering Safety Features - Reactor Building Spray - Aging Management Evaluation
- Table 3.2.2-2, Engineering Safety Features - Refueling Water - Aging Management Evaluation
- Table 3.2.2-3, Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation
- Table 3.2.2-4, Engineering Safety Features - Safety Injection - Aging Management Evaluation

3.2.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.2.2.1.1 Reactor Building Spray

Materials

The materials of construction for the reactor building spray system component types are:

- Glass
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The reactor building spray system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Gas
- Treated borated water
- Treated water
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the reactor building spray system, require management:

- Cracking
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance

Aging Management Programs

The following aging management programs manage the aging effects for the reactor building spray system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.28)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)
- Water Chemistry (B2.1.2)

3.2.2.1.2 Refueling Water

Materials

The materials of construction for the refueling water system component types are:

- Non-metallic thermal insulation
- Stainless steel

Environment

The refueling water system component types are exposed to the following environments:

- Air – outdoor
- Concrete
- Condensation
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the refueling water system, require management:

- Cracking
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance

Aging Management Programs

The following aging management programs manage the aging effects for the refueling water system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)

3.2.2.1.3 Residual Heat Removal

Materials

The materials of construction for the residual heat removal system component types are:

- Stainless steel
- Steel

Environment

The residual heat removal system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Reactor coolant
- Treated borated water
- Treated borated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the residual heat removal system, require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the residual heat removal system component types:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.2.2.1.4 Safety Injection

Materials

The materials of construction for the safety injection system component types are:

- Stainless steel
- Steel
- Steel with stainless steel cladding

Environment

The safety injection system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Gas
- Reactor coolant
- Treated borated water
- Treated borated water >60°C (>140°F)
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the safety injection system, require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the safety injection system component types:

- ASME Code Class 1 Small-Bore Piping (B2.1.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.28)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.2.2.2 Further Evaluation of Aging Management as Recommended by NUREG-2192

NUREG-2192 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the Subsequent License Renewal Application. For the engineered safety features, those evaluations are addressed in the following sections.

3.2.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

[3.2.1-001] – Fatigue of Engineered Safety Features components is a time-limited aging analysis (TLAA), as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed in Section 4.3, Metal Fatigue.

3.2.2.2.2 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor stainless steel (SS) and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant specific operating experience (OE) and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if: (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of systems, structures, and components (SSCs), the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) the GALL SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) the GALL SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, a one time inspection would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

A review of plant-specific operating experience did not identify loss of material due to pitting or crevice corrosion for stainless steel or nickel alloy piping, piping components, or tanks in air environments (air-indoor uncontrolled, air-outdoor, condensation, or underground). The absence of the aging effect in air environments will be confirmed by the One-Time Inspection (B2.1.20) program or by one-time inspections directed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.

[3.2.1-004] – Loss of material of stainless steel components exposed to air-indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program.

[3.2.1-048] – Loss of material of stainless steel components exposed to air-indoor uncontrolled (internal) is managed by the One-Time Inspection (B2.1.20) program.

[3.2.1-106] – Loss of material of stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to condensation is managed by one-time inspections directed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.

[3.2.1-107] – Loss of material of stainless steel components exposed to air – outdoor is managed by the One-Time Inspection (B2.1.20) program.

[3.2.1-112] – Loss of material of stainless steel components exposed to an underground environment is managed by the One-Time Inspection (B2.1.20) program.

3.2.2.2.3 Loss of Material Due to General Corrosion and Flow Blockage Due to Fouling

Loss of material due to general corrosion (as applicable) and flow blockage due to fouling for all materials can occur in the spray nozzles and flow orifices in the drywell and suppression chamber spray system exposed to air indoor uncontrolled. This aging effect and mechanism will apply since the carbon steel piping upstream of the spray nozzles and flow orifices is occasionally wetted, even though the majority of the time this system is in standby. The wetting and drying of these components can accelerate corrosion in the system and lead to flow blockage from an accumulation of corrosion products. Aging effects sufficient to result in a loss of intended function are not anticipated if: (a) the applicant identifies those portions of the system that are normally dry but subject to periodic wetting; (b) plant specific procedures exist to drain the normally dry portions that have been wetted during normal plant operation or inadvertently; (c) the plant specific configuration of the drains and piping allow sufficient draining to empty the normally dry pipe; (d) plant specific OE has not revealed loss of material or flow blockage due to fouling; and (e) a one time inspection is conducted to verify that loss of material or flow blockage due to fouling has not occurred. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to conduct the one time inspections. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," describes an acceptable program to manage loss of material due to general corrosion and flow blockage due to fouling when the above conditions are not met.

Not applicable - BWR only.

3.2.2.2.4 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to stress corrosion cracking (SCC) could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if: (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. The GALL SLR Report AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

A review of plant-specific operating experience did not identify instances of cracking of stainless steel in air environments (air-indoor uncontrolled, air-outdoor, condensation, or underground). The absence of the aging effect will be confirmed by the One-Time Inspection (B2.1.20) program or by one-time inspections directed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.

[3.2.1-007] – Cracking of stainless steel components exposed to air-indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program.

[3.2.1-080] – Cracking of stainless steel components exposed to an underground environment is managed by the One-Time Inspection (B2.1.20) program.

[3.2.1-103] – Cracking of stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to condensation is managed by one-time inspections directed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.

[3.2.1-108] – Cracking of stainless steel components exposed to air – outdoor is managed by the One-Time Inspection (B2.1.20) program.

3.2.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.2.2.2.6 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

3.2.2.2.7 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant specific OE reveals repetitive occurrences. The criteria for recurrence is: (a) a 10-year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5-year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10 year search of plant specific OE, two instances of a 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

Not applicable. A review of plant-specific operating experience confirms that loss of material due to recurring internal corrosion is not an aging effect that requires management for the Engineered Safety Features systems.

3.2.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of subsequent license renewal (SLR), acceptance criteria for this further evaluation are being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

Susceptible Material: If the material is not susceptible to SCC, then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

•2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper

•5xxx series alloys with a magnesium content of 3.5 weight percent or greater

•6xxx series alloys in the F temper

•7xxx series alloys in the F, T5x, or T6x temper

•2xx.x and 7xx.x series alloys

•3xx.x series alloys that contain copper

•5xx.x series alloys with a magnesium content of greater than 8 weight percent

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

Aggressive Environment: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. The GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks, which are buried or underground. The GALL SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

A review of plant-specific operating experience did not identify a history of cracking of aluminum alloy components. Contaminants similar to those that support degradation of aluminum also support degradation of stainless steel. Review of operating experience as discussed in topics 3.2.2.2.2 and 3.2.2.2.4 did not identify degradation of stainless steel components in air environments. The absence of the aging effect will be confirmed by the One-Time Inspection (B2.1.20) program

[3.2.1-101] – Cracking of uninsulated aluminum reactor coolant pump oil collection tank flame arrestors within the Reactor Building exposed to air-indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program.

3.2.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG—1557; (b) plant specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and cracking due to SCC (SS only) are identified as applicable aging effects. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

There are no in-scope steel piping or piping components exposed to concrete that are potentially exposed to groundwater in the Engineered Safety Features systems and there are no in-scope stainless steel piping components exposed to concrete in the Engineered Safety Features systems.

[3.2.1-055] - Loss of material of steel nitrogen supply piping components with an external environment of concrete that do not exit the concrete into soil is not an aging effect requiring management. Piping components within above-ground concrete (i.e., not exiting into soil) are not potentially exposed to groundwater. The concrete in areas containing this piping conforms to ACI 318. Review of plant-specific operating experience did not identify degradation of concrete around embedded components that could lead to penetration of water to the surface of embedded steel.

3.2.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if: (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) the GALL SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

A review of plant-specific operating experience did not identify a history of loss of material of aluminum alloy components. Contaminants similar to those that support degradation of aluminum also support degradation of stainless steel. Review of operating experience as discussed in topics 3.3.2.2.2 and 3.2.2.2.4 did not identify degradation of stainless steel components in air environments. The absence of the aging effect will be confirmed by the One-Time Inspection (B2.1.20) program

[3.2.1-042] – Loss of material of aluminum reactor coolant pump oil collection tank flame arrestors within the Reactor Building exposed to air-indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program.

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Results Tables: Engineered Safety Features Systems

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-001	Stainless steel, steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.2.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of stainless steel piping, piping components exposed to reactor coolant and treated borated water >60°C (>140°F) is a TLAA. See further evaluation in Section 3.2.2.2.1.
3.2.1-004	Stainless steel, nickel alloy piping, piping components exposed to air, condensation (external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. Loss of material of stainless steel components exposed to Air – indoor uncontrolled (external) is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.2.2.2.2.
3.2.1-005	Stainless steel orifice (miniflow recirculation when centrifugal HPSI pumps are used for normal charging) exposed to treated borated water	Loss of material due to erosion	AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only components in Auxiliary Systems (chemical and volume control) are aligned to this item.
3.2.1-006	Metallic drywell and suppression chamber spray system (internal surfaces): flow orifice; spray nozzles exposed to air – indoor uncontrolled, condensation	Loss of material due to general, pitting, crevice corrosion; flow blockage due to fouling	AMP XI.M32, One-Time Inspection, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Yes (SRP-SLR Section 3.2.2.2.3)	Not applicable - BWR only.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-007	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191. Cracking of stainless steel components exposed to air – indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor vessel, steam generators, and reactor coolant) are aligned to this item. See further evaluation in Section 3.2.2.2.4.
3.2.1-008	Copper alloy (>15% Zn) piping, piping components exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, Boric Acid Corrosion	No	Not applicable. There are no in-scope copper alloy (>15% Zn) piping, piping components exposed to air with borated water leakage in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-009	Steel external surfaces exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, Boric Acid Corrosion	No	Consistent with NUREG-2191.
3.2.1-010	Cast austenitic stainless steel piping, piping components exposed to treated borated water >250°C (>482°F), treated water >250°C (>482°F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	No	Not applicable. There are no in-scope cast austenitic stainless steel piping, piping components exposed to treated borated water >250°C (>482°F), or treated water >250°C (>482°F) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-011	Steel piping, piping components exposed to steam, treated water	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Not applicable. There are no steel piping, piping components exposed to steam in the Engineered Safety Features systems. The steel piping, piping components in treated water in the Engineered Safety Features systems are associated with the reactor building spray system sodium hydroxide storage tank. These components are not susceptible to FAC because they contain single phase flow well below the 200F exclusion temperature for FAC susceptibility identified in NSAC-202L. The associated NUREG-2191 aging items are not used.
3.2.1-012	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, Bolting Integrity	No	Not applicable. There is no in-scope high-strength steel closure bolting in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-014	Stainless steel, steel, nickel alloy closure bolting exposed to air-indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.2.1-015	Metallic closure bolting exposed to any environment, soil underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.2.1-016	Steel piping, piping components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.2.1-017	Aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope aluminum piping, piping components exposed to treated water or treated borated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-019	Stainless steel heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.2.1-020	Stainless steel, steel (with stainless steel or nickel alloy cladding) piping, piping components, tanks exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.2.1-022	Nickel alloy, stainless steel heat exchanger components, piping, piping components, tanks exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) and Auxiliary Systems (nuclear sampling) are aligned to this item.
3.2.1-023	Steel heat exchanger components, piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope steel heat exchanger components or piping, piping components exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-024	Stainless steel piping, piping components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope stainless steel piping, piping components exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-025	Stainless steel heat exchanger components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope stainless steel heat exchanger components exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-027	Stainless steel, steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope stainless steel or steel heat exchanger tubes exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-028	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-029	Steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope steel piping, piping components exposed to closed-cycle cooling water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-030	Steel heat exchanger components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191.
3.2.1-031	Stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.2.1-032	Copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope copper alloy heat exchanger components or piping, piping components exposed to closed-cycle cooling water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-033	Copper alloy, stainless steel heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-034	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Not applicable. There are no in-scope copper alloy (>15% Zn or >8% Al) piping, piping components or heat exchanger components exposed to closed-cycle cooling water or treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-035	Gray cast iron motor cooler exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Not applicable. There are no in-scope gray cast iron motor cooler components exposed to closed-cycle cooling water or treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-036	Gray cast iron, ductile iron piping, piping components exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Not applicable. There are no in-scope gray cast iron or ductile iron piping, piping components exposed to closed-cycle cooling water or treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-037	Gray cast iron, ductile iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Not applicable. There are no in-scope gray cast iron or ductile iron piping, piping components exposed to soil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-038	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There are no in-scope elastomer piping, piping components or seals exposed to air or condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-040	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-042	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.10)	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item. Loss of material of aluminum piping, piping components exposed to air is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.2.2.2.10.
3.2.1-043	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope elastomer piping, piping components or seals exposed to air or condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-044	Steel piping, piping components, ducting, ducting components exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only components in Steam and Power Conversion Systems (main steam) are aligned to this item.
3.2.1-045	Steel encapsulation components exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope steel encapsulation components exposed to air – indoor uncontrolled in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-046	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope steel piping, piping components exposed to condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-047	Steel encapsulation components exposed to air with borated water leakage	Loss of material due to general, pitting, crevice, boric acid corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope steel encapsulation components exposed to air with borated water leakage in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-048	Stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. Loss of material of stainless steel piping, piping components exposed to air – indoor uncontrolled (internal) is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.2.2.2.2.
3.2.1-049	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope steel piping, piping components exposed to lubricating oil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-050	Copper alloy, stainless steel piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only heat exchanger components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.2.1-051	Steel, copper alloy, stainless steel heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only heat exchanger components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.2.1-052	Steel piping, piping components exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. Loss of material of steel piping, piping components exposed to concrete is addressed in row 3.2.1-055. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-053	Stainless steel, nickel alloy piping, piping components, tanks, exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. Loss of material of stainless steel tanks exposed to concrete is addressed in row 3.2.1-129. The associated NUREG-2191 aging items are not used.
3.2.1-054	Stainless steel, nickel alloy piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	AMP XI.M7, BWR Stress Corrosion Cracking, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.2.1-055	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.2.2.2.9.
3.2.1-056	Aluminum piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no in-scope aluminum piping, piping components or tanks exposed to air or condensation (internal) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-057	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Not applicable. There are no in-scope copper alloy piping, piping components exposed to air, condensation, or gas in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-058	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. There are no in-scope copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-059	Galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled	None	None	No	Not applicable. There are no in-scope galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-060	Glass piping elements exposed to air, underground, lubricating oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, closed-cycle cooling water	None	None	No	Consistent with NUREG-2191.
3.2.1-062	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. There are no in-scope nickel alloy piping, piping components exposed to air with borated water leakage in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-063	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191.
3.2.1-064	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.2.1-065	Metallic piping, piping components exposed to treated water, treated borated water	Wall thinning due to erosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Consistent with NUREG-2191. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-066	Metallic piping, piping components, tanks exposed to raw water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Yes (SRP-SLR Section 3.2.2.2.7)	Not applicable. A review of plant-specific operating experience did not identify recurring internal corrosion in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-067	Stainless steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191.
3.2.1-068	Steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete, air, condensation	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191.
3.2.1-069	Insulated steel piping, piping components, tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components or AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Not applicable. Loss of material of steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air is addressed in row 3.2.1-068. The associated NUREG-2191 aging items are not used.
3.2.1-070	Steel, stainless steel, aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to treated water, treated borated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-071	Insulated copper alloy (>15% Zn or >8% Al) piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There are no in-scope insulated copper alloy (>15% Zn or >8% Al) piping, piping components or tanks exposed to air or condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-072	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil, condensation	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Not applicable. There are no in-scope piping, piping components, heat exchangers, or tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil, or condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-073	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil, condensation	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Not applicable. There are no in-scope piping, piping components, heat exchangers, or tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil, or condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-074	Gray cast iron, ductile iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water	Loss of material due to selective leaching	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Not applicable. There are no in-scope gray cast iron or ductile iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, or waste water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-076	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to treated water, treated borated water, raw water, waste water, lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC (steel, copper alloy in raw water, waste water only)	AMP XI.M18, Bolting Integrity	No	Not applicable. There are no in-scope stainless steel, steel, nickel alloy, or copper alloy closure bolting exposed to treated water, treated borated water, raw water, waste water, or lubricating oil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-078	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. Cracking of stainless steel, tanks exposed to concrete is addressed in row 3.2.1-067. VCSNS soil does not correspond to a carbonate/bicarbonate environment. The associated NUREG-2191 aging items are not used.
3.2.1-079	Stainless steel closure bolting exposed to air, soil, concrete, underground	Cracking due to SCC	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.2.1-080	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191. Cracking of stainless steel underground piping, piping components is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.2.2.2.4.
3.2.1-081	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There are no in-scope stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes exposed to air or condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-087	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-090	Steel components exposed to treated water, treated borated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.2.1-091	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Not applicable. There are no in-scope stainless steel piping, piping components exposed to concrete in the Engineered Safety Features systems. Aging of stainless steel tanks exposed to concrete is addressed in rows 3.2.1-067 and 3.2.1-129. The associated NUREG-2191 aging items are not used.
3.2.1-096	Steel, stainless steel piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope steel or stainless steel piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-098	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Not applicable. There are no in-scope copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-099	Stainless steel, nickel alloy tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.2)	Not applicable. Loss of material of stainless steel tanks exposed to condensation is addressed in row 3.2.1-106. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-100	Aluminum piping, piping components, tanks exposed to air, condensation (internal), raw water, waste water	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. There are no in-scope aluminum piping, piping components, or tanks exposed to air, condensation (internal), raw water, or waste water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-101	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.8)	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only piping, piping components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item. Cracking of aluminum piping, piping components exposed to air – indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.2.2.2.8.
3.2.1-102	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. There are no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, or waste water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-103	Stainless steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191. Cracking of stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to condensation is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program. See further evaluation in Section 3.2.2.2.4.
3.2.1-104	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Not applicable. There are no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-105	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-106	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. Loss of material of stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to condensation is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program. See further evaluation in Section 3.2.2.2.2.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-107	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. Loss of material of insulated stainless steel piping, piping components exposed to air – outdoor is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.2.2.2.2.
3.2.1-108	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191. Cracking of insulated stainless steel piping, piping components exposed to air – outdoor is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.2.2.2.4.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-109	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. There are no in-scope insulated aluminum piping, piping components, or tanks exposed to air, condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-110	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. There are no in-scope aluminum underground piping, piping components, or tanks in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-111	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no in-scope aluminum underground piping, piping components, or tanks in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-112	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. Loss of material of stainless steel underground piping, piping components is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.2.2.2.2.
3.2.1-114	Stainless steel, nickel alloy piping, piping components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only heat exchanger components in Auxiliary Systems (nuclear sampling) are aligned to this item.
3.2.1-115	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope titanium heat exchanger tubes exposed to treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-116	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not applicable. There are no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, or piping, piping components exposed to treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-117	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope titanium heat exchanger tubes exposed to closed-cycle cooling water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-118	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not applicable. There are no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, or piping, piping components exposed to closed-cycle cooling water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-119	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no in-scope insulated aluminum piping, piping components or tanks exposed to air or condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-120	Aluminum piping, piping components, tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope aluminum piping, piping components or tanks exposed to soil or concrete in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-121	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There are no in-scope elastomer piping, piping components or seals exposed to air in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope elastomer piping, piping components or seals exposed to air in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-124	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. There are no in-scope aluminum piping, piping components or tanks exposed to air with borated water leakage in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-125	Steel closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Consistent with NUREG-2191.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-126	Titanium, super austenitic piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to pitting, crevice corrosion, MIC (except for titanium; soil environment only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope titanium or super austenitic piping, piping components, tanks, or closure bolting exposed to soil, concrete, or underground in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-127	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. There are no in-scope copper alloy piping, piping components exposed to concrete in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-128	Copper alloy piping, piping components exposed to soil, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope copper alloy piping, piping components exposed to soil or underground in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-129	Stainless steel tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191.
3.2.1-130	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only heat exchanger components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.2.1-131	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope aluminum piping, piping components exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-132	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-133	Titanium piping, piping components, heat exchanger components exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope titanium piping, piping components or heat exchanger components exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-134	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope polymeric piping, piping components, ducting, ducting components, or seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, or soil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Results Tables: Engineered Safety Features AMR Results

Table 3.2.2-1 Engineering Safety Features - Reactor Building Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	V.E.E-468	3.2.1-125	A, 1
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A, 1
Flow element	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Insulation (safety-related heat traced components)	TI	Non-metallic thermal insulation	(E) Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-422	3.2.1-087	A
Orifice	PB;RF;SI	Stainless steel	(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A

Table 3.2.2-1 Engineering Safety Features - Reactor Building Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(E) Underground	Cracking	One-Time Inspection (B2.1.20)	V.E.E-423a	3.2.1-080	A, 1
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-455a	3.2.1-112	A, 1
		Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	V.D1.E-434	3.2.1-090	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-62	3.2.1-016	A
					Water Chemistry (B2.1.2)	V.C.EP-62	3.2.1-016	A
Pump casing (reactor building spray)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Pump casing (sodium hydroxide recirculation)	SI	Stainless steel	(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Sight glass	SI	Glass	(E) Air – outdoor	None	None	V.F.EP-15	3.2.1-060	A
			(I) Treated water	None	None	V.F.EP-29	3.2.1-060	A

Table 3.2.2-1 Engineering Safety Features - Reactor Building Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass (body)	SI	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	V.D1.E-434	3.2.1-090	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-62	3.2.1-016	A
					Water Chemistry (B2.1.2)	V.C.EP-62	3.2.1-016	A
Spray nozzle	SP	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-81b	3.2.1-048	A
Strainer body (element removed)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Tank (sodium hydroxide storage)	PB	Steel	(E) Air – outdoor	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-402	3.2.1-068	A
			(E) Concrete	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-402	3.2.1-068	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	V.D1.E-434	3.2.1-090	A
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-404	3.2.1-070	A

Table 3.2.2-1 Engineering Safety Features - Reactor Building Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	PB;SI	Stainless steel	(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(E) Underground	Cracking	One-Time Inspection (B2.1.20)	V.E.E-423a	3.2.1-080	A, 1
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-455a	3.2.1-112	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A

Table 3.2.2-1 Plant-Specific Notes:

1. Underground environment is used for components within Reactor Building sump guard pipes and isolation valve chambers.

Table 3.2.2-2 Engineering Safety Features - Refueling Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Stainless steel	(E) Condensation	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
Insulation (refueling water storage tank)	TI	Non-metallic thermal insulation	(E) Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-422	3.2.1-087	A
Tank (refueling water storage tank - anti-vortex baffle)	FD	Stainless steel	(E) Treated borated water	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.A.E-404	3.2.1-070	A
Tank (refueling water storage tank)	PB	Stainless steel	(E) Concrete	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-405	3.2.1-067	A
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-472	3.2.1-129	A
			(E) Condensation	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-446a	3.2.1-103	A
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-449a	3.2.1-106	A
			(I) Treated borated water	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.A.E-404	3.2.1-070	A

Table 3.2.2-2 Plant-Specific Notes: None

Table 3.2.2-3 Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	V.E.E-421	3.2.1-079	A
				Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
Flow element	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Heat exchanger (pump seal cooler - cover)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-93	3.2.1-031	A
Heat exchanger (pump seal cooler - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-92	3.2.1-030	A

Table 3.2.2-3 Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (pump seal cooler - tube)	HT;PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-93	3.2.1-031	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.D1.EP-96	3.2.1-033	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	C
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	C
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	V.D1.E-20	3.2.1-019	A
					Water Chemistry (B2.1.2)	V.D1.E-20	3.2.1-019	A
Heat exchanger (residual heat - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	C
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	C
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Heat exchanger (residual heat - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-92	3.2.1-030	A
Heat exchanger (residual heat - tube)	HT;PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-93	3.2.1-031	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.D1.EP-96	3.2.1-033	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	C
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	C
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	V.D1.E-20	3.2.1-019	A
					Water Chemistry (B2.1.2)	V.D1.E-20	3.2.1-019	A

Table 3.2.2-3 Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (residual heat - tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-93	3.2.1-031	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	C
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	C
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	V.D1.E-407	3.2.1-065	A
Piping, piping components (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	V.D1.E-407	3.2.1-065	A

Table 3.2.2-3 Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (residual heat removal)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Valve body (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.2.2-3 Plant-Specific Notes: None

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	V.E.E-421	3.2.1-079	A
				Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Underground	Cracking	Bolting Integrity (B2.1.9)	V.E.E-421	3.2.1-079	A, 2
				Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-243	3.3.1-108	A, 2
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A, 2
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
Containment sump strainer (frame, element and duct)	FLT	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
Flow element	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-81b	3.2.1-048	A
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	V.D1.E-407	3.2.1-065	A
			(E) Underground	Cracking	One-Time Inspection (B2.1.20)	V.E.E-423a	3.2.1-080	A, 2
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-455a	3.2.1-112	A, 2
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(E) Concrete	None	None	V.F.EP-112	3.2.1-055	A, 1
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A
Piping, piping components (Class 1 <NPS 4)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Reactor coolant	Cracking	ASME Code Class 1 Small-Bore Piping (B2.1.22)	IV.C2.RP-235	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-235	3.1.1-039	A
					Water Chemistry (B2.1.2)	IV.C2.RP-235	3.1.1-039	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	V.D1.E-407	3.2.1-065	A
Pump casing (hydro-test)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Tank (accumulator)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(E) Underground	Cracking	One-Time Inspection (B2.1.20)	V.E.E-423a	3.2.1-080	A, 2
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-455a	3.2.1-112	A, 2
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A
Valve body (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.D1.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-107a	3.2.1-004	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.2.2-4 Plant-Specific Notes:

1. Line item represents nitrogen supply piping embedded within above-ground concrete that is not potentially exposed to groundwater.
2. Underground environment is used for components within Reactor Building sump guard pipes and isolation valve chambers.

Tables 3.2.2-1 through 3.2.2-4 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

F. Material not in NUREG-2191 for this component.

G. Environment not in NUREG-2191 for this component and material.

H. Aging effect not in NUREG-2191 for this component, material and environment combination.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

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3.3 AGING MANAGEMENT OF AUXILIARY SYSTEMS

3.3.1 Introduction

This section provides the results of the aging management review for those components identified in Section 2.3.3, Auxiliary Systems, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Air Handling and Local Ventilation and Cooling (Section 2.3.3.1)
- Auxiliary Coolant (Section 2.3.3.2)
- Boron Recycle (Section 2.3.3.3)
- Building Services (Section 2.3.3.4)
- Chemical and Volume Control (Section 2.3.3.5)
- Chilled Water (Section 2.3.3.6)
- Circulating Water (Section 2.3.3.7)
- Component Cooling (Section 2.3.3.8)
- Demineralized Water - Nuclear Services (Section 2.3.3.9)
- Diesel Generator Services (Section 2.3.3.10)
- Domestic Water (Section 2.3.3.11)
- Excess Liquid Waste (Section 2.3.3.12)
- Fire Service (Section 2.3.3.13)
- Fuel Handling (Section 2.3.3.14)
- Gaseous Waste Processing (Section 2.3.3.15)
- Hydrogen Removal, Post Accident (Section 2.3.3.16)
- Incore Instrumentation (Section 2.3.3.17)
- Industrial Cooler (Section 2.3.3.18)
- Instrument Air (Section 2.3.3.19)
- Leak Detection (Section 2.3.3.20)
- Liquid Effluents From Nuclear Plant to Penstock (Section 2.3.3.21)
- Liquid Waste Processing (Section 2.3.3.22)
- Material Handling (Section 2.3.3.23)
- Nitrogen Blanketing (Section 2.3.3.24)
- Nuclear and Miscellaneous Drains (Section 2.3.3.25)

- Nuclear Sampling (Section 2.3.3.26)
- Radiation Monitoring (Section 2.3.3.27)
- Radwaste Solidification & Solids Handling (Section 2.3.3.28)
- Reactor Building Cooling Unit Drains (Section 2.3.3.29)
- Reactor Building Leak Rate Testing (Section 2.3.3.30)
- Reactor Makeup Water Supply (Section 2.3.3.31)
- Service Water (Section 2.3.3.32)
- Spent Fuel Cooling (Section 2.3.3.33)
- Station Service Air (Section 2.3.3.34)
- Thermal Regeneration (Section 2.3.3.35)

3.3.2 Results

The following tables summarize the results of the aging management review for Auxiliary Systems.

- Table 3.3.2-1, Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation
- Table 3.3.2-2, Auxiliary Systems - Auxiliary Coolant - Aging Management Evaluation
- Table 3.3.2-3, Auxiliary Systems - Boron Recycle - Aging Management Evaluation
- Table 3.3.2-4, Auxiliary Systems - Building Services - Aging Management Evaluation
- Table 3.3.2-5, Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation
- Table 3.3.2-6, Auxiliary Systems - Chilled Water - Aging Management Evaluation
- Table 3.3.2-7, Auxiliary Systems - Circulating Water - Aging Management Evaluation
- Table 3.3.2-8, Auxiliary Systems - Component Cooling - Aging Management Evaluation
- Table 3.3.2-9, Auxiliary Systems - Demineralized Water - Nuclear Services - Aging Management Evaluation
- Table 3.3.2-10, Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation
- Table 3.3.2-11, Auxiliary Systems - Domestic Water - Aging Management Evaluation
- Table 3.3.2-12, Auxiliary Systems - Excess Liquid Waste - Aging Management Evaluation
- Table 3.3.2-13, Auxiliary Systems - Fire Service - Aging Management Evaluation
- Table 3.3.2-14, Auxiliary Systems - Fuel Handling - Aging Management Evaluation
- Table 3.3.2-15, Auxiliary Systems - Gaseous Waste Processing - Aging Management Evaluation
- Table 3.3.2-16, Auxiliary Systems - Hydrogen Removal, Post Accident - Aging Management Evaluation
- Table 3.3.2-18, Auxiliary Systems - Industrial Cooler - Aging Management Evaluation
- Table 3.3.2-19, Auxiliary Systems - Instrument Air - Aging Management Evaluation
- Table 3.3.2-20, Auxiliary Systems - Leak Detection - Aging Management Evaluation
- Table 3.3.2-21, Auxiliary Systems - Liquid Effluents From Nuclear Plant to Penstock - Aging Management Evaluation
- Table 3.3.2-22, Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation
- Table 3.3.2-23, Auxiliary Systems - Material Handling - Aging Management Evaluation

3.3.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.3.2.1.1 Air Handling and Local Ventilation and Cooling

Materials

The materials of construction for the air handling and local ventilation and cooling system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Elastomer
- Stainless steel
- Steel

Environment

The air handling and local ventilation and cooling system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Closed-cycle cooling water
- Condensation
- Raw water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the air handling and local ventilation and cooling system, require management:

- Cracking
- Flow blockage
- Hardening or loss of strength
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the air handling and local ventilation and cooling system component types:

- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Fire Protection (B2.1.15)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.2 Auxiliary Coolant

Materials

The materials of construction for the auxiliary coolant system component types are:

- Ductile iron
- Stainless steel
- Steel

Environment

The auxiliary coolant system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the auxiliary coolant system, require management:

- Cracking
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the auxiliary coolant system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.3 Boron Recycle

Materials

The materials of construction for the boron recycle system component types are:

- Glass
- Stainless steel
- Steel

Environment

The boron recycle system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Steam
- Treated borated water
- Treated borated water >60°C (>140°F)
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the boron recycle system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the boron recycle system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.4 Building Services

Materials

The materials of construction for the building services system component types are:

- Stainless steel

Environment

The building services system component types are exposed to the following environments:

- Air – indoor uncontrolled

Aging Effects Requiring Management

The following aging effects, associated with the building services system, require management:

- Cracking
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the building services system component types:

- One-Time Inspection (B2.1.20)

3.3.2.1.5 Chemical and Volume Control

Materials

The materials of construction for the chemical and volume control system component types are:

- Copper alloy
- Elastomer
- Glass
- Gray cast iron
- Nickel alloy
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The chemical and volume control system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Gas
- Lubricating oil
- Reactor coolant
- Steam
- Treated borated water
- Treated borated water >60°C (>140°F)
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the chemical and volume control system, require management:

- Cracking
- Cumulative fatigue damage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the chemical and volume control system component types:

- ASME Code Class 1 Small-Bore Piping (B2.1.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.6 Chilled Water

Materials

The materials of construction for the chilled water system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Glass
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The chilled water system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Condensation
- Gas
- Lubricating oil
- Raw water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the chilled water system, require management:

- Cracking
- Flow blockage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the chilled water system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)

3.3.2.1.7 Circulating Water

Materials

The materials of construction for the circulating water system component types are:

- Gray cast iron
- Stainless steel
- Steel

Environment

The circulating water system component types are exposed to the following environments:

- Raw water

Aging Effects Requiring Management

The following aging effects, associated with the circulating water system, require management:

- Flow blockage
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the circulating water system component types:

- Bolting Integrity (B2.1.9)
- Fire Water System (B2.1.16)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.8 Component Cooling

Materials

The materials of construction for the component cooling system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn)
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The component cooling system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Raw water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the component cooling system, require management:

- Cracking
- Flow blockage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the component cooling system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.9 Demineralized Water - Nuclear Services

Materials

The materials of construction for the demineralized water - nuclear services system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Stainless steel
- Steel

Environment

The demineralized water - nuclear services system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the demineralized water - nuclear services system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the demineralized water - nuclear services system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.10 Diesel Generator Services

Materials

The materials of construction for the diesel generator services system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn)
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The diesel generator services system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Closed-cycle cooling water
- Closed-cycle cooling water >60°C (>140°F)
- Condensation
- Diesel exhaust
- Fuel oil
- Gas
- Lubricating oil
- Raw water
- Soil
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the diesel generator services system, require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the diesel generator services system component types:

- Bolting Integrity (B2.1.9)
- Buried and Underground Piping and Tanks (B2.1.28)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Fuel Oil Chemistry (B2.1.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)

3.3.2.1.11 Domestic Water

Materials

The materials of construction for the domestic water system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Stainless steel
- Steel
- Steel with internal lining

Environment

The domestic water system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Raw water

Aging Effects Requiring Management

The following aging effects, associated with the domestic water system, require management:

- Cracking
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the domestic water system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.12 Excess Liquid Waste

Materials

The materials of construction for the excess liquid waste system component types are:

- Copper alloy
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The excess liquid waste system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the excess liquid waste system, require management:

- Cracking
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the excess liquid waste system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.13 Fire Service

Materials

The materials of construction for the fire service system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Ductile iron
- Ductile iron with internal coating
- Ductile iron with internal lining
- Gray cast iron
- Gray cast iron with internal lining
- Nickel alloy
- Stainless steel
- Steel

Environment

The fire service system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Diesel exhaust
- Fuel oil
- Gas
- Lubricating oil
- Raw water
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the fire service system, require management:

- Cracking
- Flow blockage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of material or cracking
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the fire service system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.28)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Fire Protection (B2.1.15)
- Fire Water System (B2.1.16)
- Fuel Oil Chemistry (B2.1.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.14 Fuel Handling

Materials

The materials of construction for the fuel handling system component types are:

- Copper alloy (>15% Zn)
- Elastomer
- Nickel alloy
- Stainless steel
- Steel

Environment

The fuel handling system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Treated borated water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the fuel handling system, require management:

- Cracking
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the fuel handling system component types:

- 10 CFR Part 50, Appendix J (B2.1.33)
- ASME Section XI, Subsection IWE (B2.1.30)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.15 Gaseous Waste Processing

Materials

The materials of construction for the gaseous waste processing system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Stainless steel
- Steel

Environment

The gaseous waste processing system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Gas
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the gaseous waste processing system, require management:

- Cracking
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the gaseous waste processing system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.16 Hydrogen Removal, Post Accident

Materials

The materials of construction for the hydrogen removal, post accident system component types are:

- Glass
- Nickel alloy
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The hydrogen removal, post accident system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the hydrogen removal, post accident system, require management:

- Cracking
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the hydrogen removal, post accident system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.17 Incore Instrumentation

Materials

The materials of construction for the incore instrumentation system component types are:

- Stainless steel

Environment

The incore instrumentation system component types are exposed to the following environments:

- Air – indoor uncontrolled

Aging Effects Requiring Management

The following aging effects, associated with the incore instrumentation system, require management:

- Cracking
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the incore instrumentation system component types:

- One-Time Inspection (B2.1.20)

3.3.2.1.18 Industrial Cooler

Materials

The materials of construction for the industrial cooler system component types are:

- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The industrial cooler system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Condensation
- Raw water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the industrial cooler system, require management:

- Cracking
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the industrial cooler system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.19 Instrument Air

Materials

The materials of construction for the instrument air system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn)
- Stainless steel
- Steel

Environment

The instrument air system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the instrument air system, require management:

- Cracking
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the instrument air system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.20 Leak Detection

Materials

The materials of construction for the leak detection system component types are:

- Glass
- Stainless steel
- Steel

Environment

The leak detection system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated borated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the leak detection system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the leak detection system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.21 Liquid Effluents From Nuclear Plant to Penstock

Materials

The materials of construction for the liquid effluents from nuclear plant to penstock system component types are:

- Stainless steel
- Steel

Environment

The liquid effluents from nuclear plant to penstock system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the liquid effluents from nuclear plant to penstock system, require management:

- Cracking
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the liquid effluents from nuclear plant to penstock system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.22 Liquid Waste Processing

Materials

The materials of construction for the liquid waste processing system component types are:

- Glass
- Stainless steel
- Steel

Environment

The liquid waste processing system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Gas
- Steam
- Treated borated water
- Treated water
- Waste water
- Waste water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the liquid waste processing system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the liquid waste processing system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.23 Material Handling

Materials

The materials of construction for the material handling system component types are:

- Stainless steel
- Steel

Environment

The material handling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the material handling system, require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the material handling system component types:

- Boric Acid Corrosion (B2.1.4)
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)
- One-Time Inspection (B2.1.20)
- Structures Monitoring (B2.1.35)
- Water Chemistry (B2.1.2)

3.3.2.1.24 Nitrogen Blanketing

Materials

The materials of construction for the nitrogen blanketing system component types are:

- Stainless steel
- Steel

Environment

The nitrogen blanketing system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Gas

Aging Effects Requiring Management

The following aging effects, associated with the nitrogen blanketing system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the nitrogen blanketing system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.25 Nuclear and Miscellaneous Drains

Materials

The materials of construction for the nuclear and miscellaneous drains system component types are:

- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The nuclear and miscellaneous drains system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Treated borated water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the nuclear and miscellaneous drains system, require management:

- Cracking
- Flow blockage
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the nuclear and miscellaneous drains system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.26 Nuclear Sampling

Materials

The materials of construction for the nuclear sampling system component types are:

- Copper alloy
- Elastomer
- Gray cast iron
- Nickel alloy
- Polymer
- Stainless steel
- Steel

Environment

The nuclear sampling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Condensation
- Gas
- Treated borated water
- Treated borated water >60°C (>140°F)
- Treated water
- Treated water >60°C (>140°F)
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the nuclear sampling system, require management:

- Cracking
- Cracking or blistering
- Cumulative fatigue damage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the nuclear sampling system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.27 Radiation Monitoring

Materials

The materials of construction for the radiation monitoring system component types are:

- Stainless steel

Environment

The radiation monitoring system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Treated borated water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the radiation monitoring system, require management:

- Cracking
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the radiation monitoring system component types:

- Closed Treated Water Systems (B2.1.12)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.28 Radwaste Solidification & Solids Handling

Materials

The materials of construction for the radwaste solidification & solids handling system component types are:

- Elastomer
- Stainless steel
- Steel

Environment

The radwaste solidification & solids handling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Waste water
- Waste water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the radwaste solidification & solids handling system, require management:

- Cracking
- Hardening or loss of strength
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the radwaste solidification & solids handling system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.29 Reactor Building Cooling Unit Drains

Materials

The materials of construction for the reactor building cooling unit drains system component types are:

- Stainless steel
- Steel

Environment

The reactor building cooling unit drains system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the reactor building cooling unit drains system, require management:

- Cracking
- Flow blockage
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the reactor building cooling unit drains system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.30 Reactor Building Leak Rate Testing

Materials

The materials of construction for the reactor building leak rate testing system component types are:

- Steel

Environment

The reactor building leak rate testing system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects, associated with the reactor building leak rate testing system, require management:

- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the reactor building leak rate testing system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)

3.3.2.1.31 Reactor Makeup Water Supply

Materials

The materials of construction for the reactor makeup water supply system component types are:

- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The reactor makeup water supply system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the reactor makeup water supply system, require management:

- Cracking
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the reactor makeup water supply system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)
- Water Chemistry (B2.1.2)

3.3.2.1.32 Service Water

Materials

The materials of construction for the service water system component types are:

- Copper alloy
- Glass
- Gray cast iron
- Non-metallic thermal insulation
- Stainless steel
- Stainless steel with internal lining
- Steel
- Steel with internal lining

Environment

The service water system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Condensation
- Lubricating oil
- Raw water
- Soil
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the service water system, require management:

- Cracking
- Flow blockage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the service water system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.28)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)

3.3.2.1.33 Spent Fuel Cooling

Materials

The materials of construction for the spent fuel cooling system component types are:

- Nickel alloy
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The spent fuel cooling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Closed-cycle cooling water
- Concrete
- Treated borated water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the spent fuel cooling system, require management:

- Cracking
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the spent fuel cooling system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.34 Station Service Air

Materials

The materials of construction for the station service air system component types are:

- Stainless steel
- Steel

Environment

The station service air system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects, associated with the station service air system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the station service air system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.35 Thermal Regeneration

Materials

The materials of construction for the thermal regeneration system component types are:

- Copper alloy (>15% Zn)
- Stainless steel
- Steel

Environment

The thermal regeneration system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Condensation
- Lubricating oil
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the thermal regeneration system, require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the thermal regeneration system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.2 Further Evaluation of Aging Management as Recommended by NUREG-2192

NUREG-2192 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the Subsequent License Renewal Application. For the auxiliary systems, those evaluations are addressed in the following sections.

3.3.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

[3.3.1-001] – Load cycles of the reactor building polar crane, spent fuel pit bridge crane (fuel handling machine), reactor cavity manipulator crane (refueling machine), 125/15-ton fuel handling building crane (spent fuel cask handling crane), 3-ton fuel handling building hoist (transfer canal gate hoist), and `B' loop auxiliary crane is a time-limited aging analysis (TLAA), as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed in Section 4.7.1, Crane Load Cycle Limits.

[3.3.1-002] – Fatigue of Auxiliary Systems components is a TLAA, as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed in Section 4.3, Metal Fatigue.

3.3.2.2.2 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

Cracking due to stress corrosion cracking (SCC) and cyclic loading could occur in stainless steel (SS) PWR nonregenerative heat exchanger tubing exposed to treated borated water greater than 60 °C (Celsius) [140 (°F) (Fahrenheit)] in the chemical and volume control system. The existing AMP for monitoring and control of primary water chemistry in PWRs (GALL SLR Report AMP XI.M2, "Water Chemistry") manages the aging effects of cracking due to SCC. However, control of water chemistry does not preclude cracking due to SCC and cyclic loading. Therefore, the effectiveness of the water chemistry control program should be verified to ensure that cracking is not occurring. If a search of plant specific operating experience (OE) does not reveal that cracking has occurred in nonregenerative heat exchanger tubing, this aging effect can be considered to be adequately managed by GALL-SLR Report AMP XI.M2. However, if cracking has occurred in nonregenerative heat exchanger tubing, the GALL-SLR Report recommends that AMP XI.M21A, "Closed Treated Water Systems," be evaluated for inclusion of augmented requirements to conduct temperature and radioactivity monitoring of the shell side water, and where component configuration permits, periodic eddy current testing of tubes.

Cracking due to stress corrosion cracking and cyclic loading could occur in stainless steel PWR nonregenerative heat exchanger tubing exposed to treated borated water greater than 60 °C (140 °F) in the chemical and volume control system.

[3.3.1-003] – A review of plant-specific operating experience confirmed that cracking of nonregenerative heat exchanger tubing has not been identified. Cracking of the nonregenerative heat exchanger tubes is managed by the Water Chemistry (B2.1.2) program.

3.3.2.2.3 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to (SCC) could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated, (b) insulated, (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if: (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant specific OE review in the license renewal application (LRA).

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in GALL-SLR Report AMP XI.M32.

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. The GALL SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

A review of plant-specific operating experience did not identify cracking of stainless steel components in air environments (air-indoor uncontrolled, air-outdoor, condensation or underground). The absence of the aging effect in air environments will be confirmed by one-time inspections.

[3.3.1-004] – Cracking of stainless steel components exposed to air – indoor uncontrolled, air – outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-094a] – Cracking of stainless steel ducting components exposed to air – indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-205] – Cracking of the reactor makeup water storage tank exposed to air – outdoor is managed by a one-time inspection directed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program. Cracking of other stainless steel components exposed to air – outdoor or condensation is managed by the One-Time Inspection (B2.1.20) program.

3.3.2.2.4 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if: (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. If a barrier coating is credited for isolating a component from a potentially aggressive environment, then the barrier coating is evaluated to verify that it is impervious to the plant specific environment. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

A review of plant-specific operating experience did not identify loss of material due to pitting or crevice corrosion for stainless steel or nickel alloy piping, piping components, or tanks in air environments (air-indoor uncontrolled, air-outdoor, condensation, or underground). The absence of the aging effect in air environments will be confirmed by one-time inspections.

[3.3.1-006] – Loss of material of stainless steel or nickel alloy components exposed to air-indoor uncontrolled, air-outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-094] – Loss of material of stainless steel ducting components exposed to air-indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-222] – Loss of material of stainless steel tanks exposed to air-indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-232] – Loss of material of the reactor makeup water storage tank exposed to air – outdoor is managed by a one-time inspection directed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program. Loss of material of other stainless steel components exposed to air – outdoor or condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-241] – Loss of material of stainless steel heat exchanger components exposed to air-indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program.

3.3.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.3.2.2.6 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

3.3.2.2.7 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant specific OE reveals repetitive occurrences. The criteria for recurrence is: (a) a 10-year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5-year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M20, "Open Cycle Cooling Water System," GALL-SLR Report AMP XI.M27, "Fire Water System," or GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10 year search of plant specific OE, two instances of 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

[3.3.1-127] - The review of plant-specific operating experience has identified recurring internal corrosion (RIC) in steel piping components exposed to raw water in the service water and fire service systems. The programs noted below will manage RIC in the systems indicated.

A) Open-Cycle Cooling Water System (B2.1.11) program

As described below, the Open-Cycle Cooling Water System (B2.1.11) program will manage aspects of RIC in the service water system that are within the scope of the program. In addition, the Appendix B operating experience section for the Open-Cycle Cooling Water System (B2.1.11) program identifies corrective actions that have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences for loss of material due to RIC for service water piping and components within the scope of the Open-Cycle Cooling Water System (B2.1.11) program will be documented in accordance with the Corrective Action Program. The Open-Cycle Cooling Water System (B2.1.11) program and associated enhancements are described in Appendix B.

a) Why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function:

Loss of Material in Uncoated Steel Exposed to Raw Water

A review of OE since 2011 indicates that recurring internal corrosion (RIC) has occurred in the service water system due to microbiologically influenced corrosion (MIC) for carbon steel exposed to raw water.

Several through-wall leaks due to MIC occurred in sections of service water piping from 2011 through 2014. Corrective action involved replacing degraded sections of piping on an as-needed basis. Chemical treatment of the service water system using biocide and bio-dispersant occurred during the summer of 2012 but was intended only to reduce biological growth and fouling that were degrading heat exchanger thermal performance. Chemical treatment to address loss of material began in 2015 with the installation of a permanent chemical injection system and the use of additional chemicals. The current chemical treatment includes a macro-biocide, a micro-biocide, bio-dispersant, corrosion inhibitor, dispersant, and azole.

Several through-wall leaks, or wall thinning identified by planned volumetric examinations, have occurred due to MIC since 2012 in segments of service water piping that do not have continuous flow and do not regularly receive chemical treatment.

- Through-wall leaks have occurred from 2012 to 2018 in a section of service water piping to the service water pump house cooling coils. The cooling coils are not in service but the piping to the coils has not been abandoned and continues to contain stagnant service water without active exposure to chemical treatment. That section of pipe includes approximately 20 feet of 3-inch diameter carbon steel piping. As a corrective action for the leaks, piping replacements have been needed for several sections of piping up to 20 feet in length. As a longer-term corrective action, the safety-related service water piping that provides cooling water to the cooling coils will be permanently removed from service due to concerns with recurring internal corrosion.

- Wall thinning degradation due to MIC was identified during planned ultrasonic testing (UT) examinations in 2017 in the following two locations:

    a. service water discharge piping from a reactor building cooling unit (RBCU). Since the RBCUs are normally cooled by industrial cooling water, service water does not flow in that line during normal operation, and the piping does not routinely receive chemical treatment to reduce the likelihood of MIC. Corrective action involved replacing two feet of degraded 16-inch diameter carbon steel with new carbon steel piping and the associated piping elbow.

    b. service water backflush piping for a component cooling heat exchanger. Since service water flow in that segment of piping is not continuous, chemical treatment also is not continuous. Corrective action involved replacing approximately 1.5 feet of 20-inch diameter carbon steel with new carbon steel piping.

  A plant procedure continues to direct periodic volumetric examinations of service water piping for indications of MIC-related degradation. Future indications of degradation identified during examinations will be entered into the Corrective Action Program.

- MIC-induced wall thinning degradation was identified during planned UT examinations in 2018 in service water piping that provides screen wash for the 'A' traveling screen. The degraded section of carbon steel piping was replaced with nine feet of new carbon-steel piping and fitting. In 2021, planned UT examinations identified a MIC-induced leak in service water piping providing screen wash for the 'B' traveling screen. The leak occurred at the toe of a weld for an elbow. The leak was repaired using a weld buildup.

  The service water in the supply piping for the traveling screen wash is stagnant most of the time since flow occurs for only approximately 30 minutes during each 12-hour interval thus reducing the effectiveness of the chemical treatment to mitigate occurrence of MIC. A plant procedure continues to direct periodic volumetric examinations of service water piping for indications of MIC-related degradation. Future indications of degradation identified during the inspections will be entered into the Corrective Action Program.

b) Basis for the adequacy of augmented or lack of augmented inspections:

The periodic inspections that are performed to identify occurrences of RIC due to MIC, and the resolution of findings using the Corrective Action Program, are adequate for the detection of loss of material without implementing augmented inspections. Corrective action has included piping replacements as necessary, and adjustments of the chemical treatment for the service water system. The decreasing frequency of MIC-related degradation since 2015 confirms the adequacy of existing inspections and corrective actions.

c) What parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change):

Trending of MIC-related degradation of service water piping is accomplished using the Corrective Action Program. For example, past MIC-related OE prompted evaluation and adjustments of the chemical treatments for the service water system. Those chemical treatments were implemented in 2012 to inhibit biological growth and fouling to reduce loss of material due to MIC. Additional adjustments of the chemical treatments have occurred as needed based on OE. Subsequent OE indicates that the ongoing chemical treatments have been effective in addressing MIC. An increasing trend of degradation due to MIC would require an evaluation for changes in the frequency or scope of inspections, and consideration of changes for the chemical treatment.

d) How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:

The Buried and Underground Piping and Tanks program (B2.1.28) manages the aging effects on external surfaces of buried and underground service water piping and components. Service water system piping discussed in this section is accessible for examination.

e) How leaks in any involved buried or underground components will be identified:

Service water system leakage testing is performed in accordance with a station procedure. Access is available if leakage is suspected for buried and underground portions of the system to identify locations of leaks using visual and volumetric examinations.

B. Fire Water System (B2.1.16) program

As described below, the Fire Water System (B2.1.16) program will manage RIC in the fire protection system. In addition, the Appendix B operating experience section for the Fire Water System (B2.1.16) program identifies corrective actions have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences of RIC in piping and components within the scope of the Fire Water System (B2.1.16) program will be documented in accordance with the Corrective Action Program. The Fire Water System (B2.1.16) program and associated enhancements are described in Appendix B.

a) Why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function:

Periodic fire protection system piping flushes, flow testing and proposed piping thickness measurements will be performed to identify pipe degradation prior to loss of system intended function. In addition to recent piping replacements in the Auxiliary Building and Intermediate Building to address instances of RIC due to microbiologically influenced corrosion, Low Frequency Electromagnetic Technique (LFET) or similar technique will be used for screening 100 feet of piping during each refueling cycle to detect changes in the wall thickness of the pipe. Thinned areas found during the LFET scan are followed up with wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

b) Basis for the adequacy of augmented or lack of augmented inspections:

Currently performed flow testing and proposed thickness measurements will provide sufficient data for trending fire water system pipe wall conditions prior to loss of intended function. Inspection samples for the 100 feet of piping will be selected from piping not previously replaced or inspected and determined to be potentially susceptible to RIC based on prior piping replacements or inspection results that require trending. Identified degraded pipe due to corrosion has been evaluated and replaced when necessary prior to loss of intended function. Other than proposed wall thickness measurements and opportunistic inspections, additional augmented inspections to detect RIC are not required.

c) What parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change):

Parameters trended during piping flow tests include flow rates, pressure drops, calculated friction losses and/or signs of debris from corrosion. Parameters trended are pipe wall thickness measurements identified as a result of LFET results. When degraded conditions are identified, engineering evaluations are performed to determine the cause. If corrosion is identified, engineering evaluation will determine if additional inspections are required, the appropriate frequency of the inspection based on the projected corrosion rate, extent of condition for other areas in the system, and necessary repairs, if required.

d) How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:

Buried fire protection system piping is made of cast iron or ductile iron with a cementitious lining. In July 2022, five ring sections were cut from three pipe segments of ductile cast iron piping to assess the condition of buried fire service components. The inspections identified no internal corrosion and the cement ling was found to be intact and tightly adhering for all ring samples. Future inspections on underground fire main piping will be performed on an opportunistic basis when corrective maintenance work is performed on the fire service buried piping.

e) How leaks in any involved buried or underground components will be identified:

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. A low-pressure condition that is beyond the ability of the jockey pump to maintain system pressure is alarmed in the main control room by the auto start of the electric motor driven fire pump, followed by the start of the diesel-driven fire pump if the system pressure continues to decrease. The status of the fire pumps is indicated in the main control room. Both fire pumps may be manually started from the main control room. The combination of continuous monitoring of the fire protection system header pressure and the associated alarm with operator actions are sufficient activities for the identification of leaks in the fire protection system buried components.

C. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program

As described below, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will manage RIC in portions of the service water system that are not within the scope of the Open-Cycle Cooling Water System (B2.1.11) program. In addition, the Appendix B operating experience section for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program identifies corrective actions have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences of RIC in piping and components within the scope of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will be documented in accordance with the Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program and associated enhancements are described in Appendix B.

a) Why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function:

Periodic visual and volumetric (UT) examinations are performed to identify loss of material due to RIC. A review of operating experience since 2011 indicates that recurring internal corrosion (RIC) has occurred in nonsafety-related portions of the service water system due to microbiologically influenced corrosion (MIC). Loss of material due to MIC has resulted in through-wall leakage twice in 2014. Resolutions have been provided through the Corrective Action Program, including the installation of a permanent service water chemical addition system in 2015 for injecting biocide and corrosion inhibitor. The decreasing frequency of MIC-related degradation since 2015 confirms the adequacy of existing inspections and corrective actions, including the chemistry adjustments.

b) Basis for the adequacy of augmented or lack of augmented inspections:

The periodic inspections that are performed to identify occurrences of RIC due to MIC, and the resolution of findings using the Corrective Action Program, are adequate for the detection of loss of material due to MIC without implementing augmented inspections. Corrective action has included component replacement as necessary, and adjustments of the chemical treatment for the service water system. The decreasing frequency of MIC-related degradation since 2015 confirms the adequacy of existing inspections and corrective actions.

c) What parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change):

Trending of MIC-related degradation of service water piping is accomplished using the Corrective Action Program. For example, past MIC-related OE prompted evaluation and adjustments of the chemical treatments for the service water system. Those chemical treatments were implemented in 2012 to inhibit biological growth and fouling to reduce loss of material due to MIC. Additional adjustments of the chemical treatments have occurred as needed based on OE. The current chemical treatment includes a macro-biocide, a micro-biocide, bio-dispersant, corrosion inhibitor, dispersant, and azole. These chemicals have been in use since 2015, and OE indicates that the ongoing chemical treatments have been effective in addressing MIC. An increasing trend of degradation due to MIC would require an evaluation for changes in the frequency or scope of inspections, and consideration of changes for the chemical treatment.

d) How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:

There are no buried/underground service water piping and components in-scope for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Inspection of buried/underground service water piping and components are conducted by the Open-Cycle Cooling Water System (B2.1.11) program.

e) How leaks in any involved buried or underground components will be identified:

There are no buried/underground service water piping and components in-scope for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Inspection of buried/underground service water piping and components are conducted by the Open-Cycle Cooling Water System (B2.1.11) program.

3.3.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation is being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

Susceptible Material: If the material is not susceptible to SCC then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

Aggressive Environment: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. If a barrier coating is credited for isolating an aluminum alloy from a potentially aggressive environment, then the barrier coating is evaluated to verify that it is impervious to the plant-specific environment. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Cracking due to stress corrosion cracking is an aging effect requiring management for aluminum alloy components exposed to air – indoor uncontrolled, air – outdoor, or waste water in the Auxiliary Systems.

[3.3.1-189] – This item addresses cracking of aluminum components exposed to air – indoor uncontrolled, air – outdoor, or waste water. There are no known sources of halides associated with indoor or outdoor air. The following component types in the identified systems are exposed to air – indoor uncontrolled, air – outdoor, or waste water and are constructed of aluminum alloys that are assumed to be susceptible to SCC because the specific series of the aluminum alloy is unknown.

Flame arrestors associated with the diesel generator fuel oil subsystem; These components are exposed to an air - indoor uncontrolled or air – outdoor environment with no known sources of halides.

Drain trap body in the instrument air system; The external surface of the trap is exposed to an air – indoor uncontrolled environment within the Auxiliary Building with no known sources of halides.

Pump motor air cooler fins in the component cooling system; These components are exposed to an air - indoor uncontrolled environment with no known sources of halides.

A review of plant-specific operating experience did not identify a history of cracking of aluminum alloy components. The absence of the aging effect in the air – indoor uncontrolled and air – outdoor environments will be confirmed by the One-Time Inspection (B2.1.20) program.

The internal surface of the instrument air system drain trap is exposed to waste water from the condensation of compressed air downstream of the standby instrument air compressor. While there are no known sources of halides in the area, the potential for this condensation to concentrate contaminants within the waste water is assumed to result in the presence of contaminants sufficient to support cracking. Cracking of aluminum drain trap exposed to waste water will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.

3.3.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG—1557; (b) plant specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components, loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) are identified as applicable aging effects. GALL SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

Loss of material due to general, crevice, or pitting corrosion can occur in steel and stainless steel components exposed to concrete.

[3.3.1-112] – Loss of material of steel piping components with an external environment of concrete that do not exit the concrete into soil is not an aging effect requiring management. Piping components that do not exit the concrete into soil are not potentially exposed to groundwater. Steel piping components exposed to concrete in the nuclear and miscellaneous drains system are embedded within interior concrete structures and are not potentially exposed to groundwater. The concrete in areas containing these components conforms to ACI 318. Review of plant-specific operating experience did not identify degradation of concrete around embedded components that could lead to penetration of water.

[3.3.1-202] – Loss of material and cracking of stainless steel components exposed to concrete is not an aging effect for components that are not potentially exposed to groundwater. Stainless steel piping components exposed to concrete in the spent fuel cooling system are embedded within interior concrete structures and are not potentially exposed to groundwater.

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should generally be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should generally be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if: (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks", for tanks; (ii) GALL SLR Report AMP XI.M36,'External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. If a barrier coating is credited for isolating an aluminum alloy from a potentially aggressive environment, then the barrier coating is evaluated to verify that it is impervious to the plant specific environment. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

Loss of material is an aging effect requiring management for aluminum alloy components exposed to air – indoor uncontrolled, air – outdoor, or waste water in the Auxiliary Systems.

[3.3.1-234] – A review of plant-specific operating experience did not identify a history of loss of material of aluminum alloy components. Loss of material of aluminum components exposed to air – indoor uncontrolled or air – outdoor is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-247] – Loss of material of aluminum components exposed to waste water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.

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Results Tables: Auxiliary Systems

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-001	Steel cranes: bridges, structural members, structural components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.7 Other Plant-Specific TLAAs	Yes (SRP-SLR Section 3.3.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel crane rails and retaining clips, girders, beams, and plates exposed to air - indoor uncontrolled is a TLAA. See further evaluation in Section 3.3.2.2.1.
3.3.1-002	Stainless steel, steel heat exchanger components and tubes, piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.3.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of stainless steel and steel components exposed to diesel exhaust, steam, treated borated water >60°C (>140°F), or treated water >60°C (>140°F) is a TLAA. In addition to Auxiliary Systems, components in Steam and Power Conversion Systems (feedwater, main steam, and turbine cycle sampling) are aligned to this item. See further evaluation in Section 3.3.2.2.1.
3.3.1-003	Stainless steel heat exchanger tubing, non-regenerative exposed to treated borated water >60°C (>140°F)	Cracking due to SCC; cyclic loading	AMP XI.M2, Water Chemistry	Yes (SRP-SLR Section 3.3.2.2.2)	Consistent with NUREG-2191. See further evaluation in Section 3.3.2.2.2.
3.3.1-003a	Stainless steel heat exchanger tubing, non-regenerative exposed to treated borated water >60°C (>140°F)	Cracking due to SCC; cyclic loading	AMP XI.M2, Water Chemistry, and AMP XI.M21A, Closed Treated Water Systems	Yes (SRP-SLR Section 3.3.2.2.2)	Not applicable. Cracking of the stainless steel non-regenerative heat exchanger tubes is addressed in row 3.3.1-003. See further evaluation in Section 3.3.2.2.2.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-004	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. Cracking of stainless steel components exposed to air – indoor uncontrolled, air – outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.3.
3.3.1-006	Stainless steel, nickel alloy piping, piping components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. Loss of material of stainless steel components exposed to air – indoor uncontrolled, air – outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.4.
3.3.1-007	Stainless steel high-pressure pump, casing exposed to treated borated water	Cracking due to cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
3.3.1-008	Stainless steel heat exchanger components and tubes exposed to treated borated water >60°C (>140°F)	Cracking due to cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-009	Steel, copper alloy (>15% Zn) external surfaces, piping, piping components exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, Boric Acid Corrosion	No	Consistent with NUREG-2191.
3.3.1-010	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, Bolting Integrity	No	Not applicable. There are no in-scope high-strength steel closure bolting exposed to air, soil, or underground in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-012	Steel; stainless steel, nickel alloy closure bolting exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.3.1-015	Metallic closure bolting exposed to any environment, soil, underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.3.1-016	Stainless steel piping, piping components outboard the second containment isolation valves with a diameter ,â•4 inches nominal pipe size exposed to treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	AMP XI.M2, Water Chemistry, and AMP XI.M25, BWR Reactor Water Cleanup System	No	Not applicable - BWR only.
3.3.1-017	Stainless steel heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-018	Stainless steel high-pressure pump casing, piping, piping components, tanks exposed to treated borated water >60°C (>140°F), sodium pentaborate solution >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope stainless steel high-pressure pump casing, piping, piping components, or tanks exposed to treated borated water >60°C (>140°F) or sodium pentaborate solution >60°C (>140°F) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-019	Stainless steel regenerative heat exchanger components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.3.1-020	Stainless steel, steel with stainless steel cladding heat exchanger components exposed to treated borated water >60°C (>140°F), treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.3.1-021	Steel piping, piping components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.3.1-022	Copper alloy piping, piping components exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.3.1-025	Aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope aluminum piping, piping components exposed to treated water or treated borated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-026	Steel (with stainless steel cladding) piping, piping components exposed to treated water	Loss of material due to general (only after cladding degradation), pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.3.1-027	Stainless steel heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.3.1-028	Stainless steel piping, piping components, tanks exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.3.1-030	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, or cementitious piping, piping components exposed to raw water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-030a	Fiberglass, HDPE piping, piping components exposed to raw water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope fiberglass or HDPE piping, piping components exposed to raw water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-034	Nickel alloy, copper alloy piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Consistent with NUREG-2191.
3.3.1-037	Steel piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Consistent with NUREG-2191.
3.3.1-038	Copper alloy, steel heat exchanger components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Consistent with NUREG-2191.
3.3.1-040	Stainless steel piping, piping components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Consistent with NUREG-2191.
3.3.1-042	Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water, raw water (potable), treated water	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M20, Open-Cycle Cooling Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. Reduction of heat transfer of copper alloy or stainless steel heat exchanger tubes exposed to raw water is managed by the Open-Cycle Cooling Water System (B2.1.11) program.
3.3.1-043	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-044	Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable - BWR only.
3.3.1-045	Steel piping, piping components, tanks exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191.
3.3.1-046	Steel, copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191.
3.3.1-047	Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable - BWR only.
3.3.1-048	Aluminum piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope aluminum piping, piping components exposed to closed-cycle cooling water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-049	Stainless steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191.
3.3.1-050	Stainless steel, copper alloy, steel heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-051	Boraflex spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron-absorbing capacity due to boraflex degradation	AMP XI.M22, Boraflex Monitoring	No	Not applicable. There are no in-scope boraflex neutron-absorbing sheets or spent fuel storage racks exposed to treated borated water or treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-052	Steel cranes: rails, bridges, structural members, structural components exposed to air	Loss of material due to general corrosion, wear, deformation, cracking	AMP XI.M23, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	No	Consistent with NUREG-2191.
3.3.1-055	Steel piping, piping components, tanks exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.
3.3.1-057	Elastomer fire barrier penetration seals exposed to air, condensation	Hardening, loss of strength, shrinkage due to elastomer degradation	AMP XI.M26, Fire Protection	No	Consistent with NUREG-2191. No Auxiliary Systems components are aligned to this item. Only components in Structural Commodities (miscellaneous structural commodities) are aligned to this item.
3.3.1-058	Steel halon/carbon dioxide fire suppression system piping, piping components exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M26, Fire Protection	No	Consistent with NUREG-2191.
3.3.1-059	Steel fire rated doors exposed to air	Loss of material due to wear	AMP XI.M26, Fire Protection	No	Consistent with NUREG-2191. No Auxiliary Systems components are aligned to this item. Only components in Containment Structure (Reactor Building) and Structures and Component Supports (Auxiliary Building, Control Building, Diesel Generator Building, Fuel Handling Building, Intermediate Building, Turbine Building, Service Water Pumphouse, and Circulating Water Intake Structure) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-060	Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M26, Fire Protection, and AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191 with a different aging management program credited for some components. No Auxiliary Systems components are aligned to this item. Only components in Containment Structure (Reactor Building) and Structures and Component Supports (Auxiliary Building, Control Building, Diesel Generator Building, Fuel Handling Building, Intermediate Building, Turbine Building, Service Water Pumphouse, and Circulating Water Intake Structure) are aligned to this item. For the Reactor Building, the ASME Section XI, Subsection IWL (B2.1.30) program is credited instead of the Structures Monitoring (B2.1.35) program.
3.3.1-063	Steel fire hydrants exposed to air – outdoor, raw water, raw water (potable), treated water	Loss of material due to general, pitting, crevice corrosion; flow blockage due to fouling (raw water, raw water (potable) only)	AMP XI.M27, Fire Water System	No	Consistent with NUREG-2191.
3.3.1-064	Steel, copper alloy piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to general (steel; copper alloy in raw water and raw water (potable) only), pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water; raw water (potable) for steel only)	AMP XI.M27, Fire Water System	No	Consistent with NUREG-2191.
3.3.1-065	Aluminum piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to pitting, crevice corrosion; flow blockage due to fouling (raw water only)	AMP XI.M27, Fire Water System	No	Not applicable. There are no in-scope aluminum piping, piping components exposed to raw water, treated water, or raw water (potable) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-066	Stainless steel piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water only)	AMP XI.M27, Fire Water System	No	Consistent with NUREG-2191.
3.3.1-069	Copper alloy piping, piping components exposed to fuel oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M30, Fuel Oil Chemistry, and AMP XI.M32, One-Time Inspection, or AMP XI.M30, Fuel Oil Chemistry	No	Consistent with NUREG-2191. Loss of material of copper alloy piping, piping components exposed to fuel oil is managed by the Fuel Oil Chemistry (B2.1.18) program and One-Time Inspection (B2.1.20) program.
3.3.1-070	Steel piping, piping components, tanks exposed to fuel oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M30, Fuel Oil Chemistry, and AMP XI.M32, One-Time Inspection, or AMP XI.M30, Fuel Oil Chemistry	No	Consistent with NUREG-2191. Loss of material of steel and gray cast iron piping, piping components and tanks exposed to fuel oil is managed by the Fuel Oil Chemistry (B2.1.18) program.
3.3.1-071	Stainless steel, aluminum, nickel alloy piping, piping components exposed to fuel oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M30, Fuel Oil Chemistry, and AMP XI.M32, One-Time Inspection, or AMP XI.M30, Fuel Oil Chemistry	No	Consistent with NUREG-2191. Loss of material of stainless steel piping, piping components exposed to fuel oil is managed by the Fuel Oil Chemistry (B2.1.18) program and the One-Time Inspection (B2.1.20) program.
3.3.1-072	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to treated water, closed-cycle cooling water, soil, raw water, raw water (potable), waste water	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-073	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to air – outdoor	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There are no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, or cementitious piping, piping components exposed to air – outdoor in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-076	Elastomer piping, piping components, ducting, ducting components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.
3.3.1-078	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Structural Commodities (miscellaneous structural commodities) are aligned to this item.
3.3.1-080	Steel heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.
3.3.1-082	Elastomer, fiberglass piping, piping components, ducting, ducting components, seals exposed to air	Loss of material due to wear	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.
3.3.1-083	Stainless steel diesel engine exhaust piping, piping components exposed to diesel exhaust	Cracking due to SCC	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-085	Elastomer piping, piping components, seals exposed to air, condensation, closed-cycle cooling water, treated borated water, treated water, raw water, raw water (potable), waste water, gas, fuel oil, lubricating oil	Hardening or loss of strength due to elastomer degradation; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191 with a different aging management program credited for some components. For the fuel handling system, the External Surfaces Monitoring of Mechanical Components (B2.1.23) program has been substituted for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program to manage the applicable aging effects of the external surfaces of the elastomer fuel pool gate seals and the reactor cavity seal ring exposed to treated borated water.
3.3.1-088	Steel; stainless steel piping, piping components, diesel engine exhaust exposed to raw water (potable), diesel exhaust	Loss of material due to general (steel only), pitting, crevice corrosion, flow blockage due to fouling (steel only for raw water (potable) environment)	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.
3.3.1-089	Steel piping, piping components exposed to condensation (internal)	Loss of material due to general, pitting, crevice corrosion	AMP XI.M27, Fire Water System	No	Not applicable. Loss of material of steel piping, piping components exposed to condensation (internal) is addressed in row 3.3.1-055 and row 3.3.1-090. The associated NUREG-2191 aging items are not used.
3.3.1-090	Steel ducting, ducting components (internal surfaces) exposed to condensation	Loss of material due to general, pitting, crevice corrosion, MIC (for drip pans and drain lines only)	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.
3.3.1-091	Steel piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. Flow blockage is not an applicable aging effect for components not credited with delivery of downstream flow.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-093	Copper alloy piping, piping components exposed to raw water (potable)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.
3.3.1-094	Stainless steel ducting, ducting components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. Loss of material of stainless steel ducting, ducting components exposed to air – indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.4.
3.3.1-094a	Stainless steel ducting, ducting components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. Cracking of stainless steel ducting, ducting components exposed to air – indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.3.
3.3.1-095	Copper alloy, stainless steel, nickel alloy piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item. Flow blockage is not an applicable aging effect for components not credited with delivery of downstream flow.
3.3.1-096	Elastomer piping, piping components, seals exposed to air, raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Steam and Power Conversion Systems (steam generator blowdown) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-096a	Steel, aluminum, copper alloy, stainless steel, titanium heat exchanger tubes internal to components exposed to air, condensation (external)	Reduction of heat transfer due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.
3.3.1-096b	Steel heat exchanger components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.
3.3.1-097	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.3.1-098	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.3.1-099	Copper alloy, aluminum piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC (copper alloy only)	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.3.1-100	Stainless steel piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.3.1-101	Aluminum heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope aluminum heat exchanger tubes exposed to lubricating oil in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-102	Boral®; boron steel, and other materials (excluding Boraflex) spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron-absorbing capacity; change in dimensions and loss of material due to effects of SFP environment	AMP XI.M40, Monitoring of Neutron-Absorbing Materials other than Boraflex	No	Consistent with NUREG-2191. No Auxiliary Systems components are aligned to this item. Only components in Structures and Component Supports (Fuel Handling Building) are aligned to this item.
3.3.1-103	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to soil, concrete	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, or cementitious piping, piping components exposed to soil or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-104	HDPE, fiberglass piping, piping components exposed to soil, concrete	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope HDPE or fiberglass piping, piping components exposed to soil or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-107	Stainless steel, nickel alloy piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. Loss of material of stainless steel reactor water makeup tank exposed to concrete is addressed in row 3.3.1-229. There are no other stainless steel or nickel alloy piping, piping components exposed to soil or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-108	Titanium, super austenitic, copper alloy, stainless steel, nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC (super austenitic, copper alloy, stainless steel, nickel alloy; soil environment only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Consistent with NUREG-2191. No Auxiliary Systems components are aligned to this item. Only components in Engineered Safety Features (safety injection) are aligned to this item.
3.3.1-109	Steel piping, piping components, closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Consistent with NUREG-2191.
3.3.1-110	Stainless steel, nickel alloy piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	AMP XI.M7, BWR Stress Corrosion Cracking, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.3.1-111	Steel structural steel exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, Structures Monitoring	No	Not applicable. There are no in-scope structural steel exposed to air - indoor uncontrolled in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-112	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.3.2.2.9.
3.3.1-113	Aluminum piping, piping components exposed to gas	None	None	No	Not applicable. There are no in-scope aluminum piping, piping components exposed to gas in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-114	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-115	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. Boric acid corrosion is not an applicable aging effect for copper alloy or copper alloy (>8% Al) piping, piping components, so air with borated water leakage environment is not assigned to these materials. The associated NUREG-2191 aging items are not used.
3.3.1-116	Galvanized steel piping, piping components exposed to air – indoor uncontrolled	None	None	No	Not applicable. There are no in-scope galvanized steel piping, piping components exposed to air – indoor uncontrolled in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-117	Glass piping elements exposed to air, lubricating oil, closed-cycle cooling water, fuel oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, underground	None	None	No	Consistent with NUREG-2191.
3.3.1-119	Nickel alloy, PVC, glass piping, piping components exposed to air with borated water leakage, air – indoor uncontrolled, condensation, waste water, raw water (potable)	None	None	No	Consistent with NUREG-2191.
3.3.1-120	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191.
3.3.1-121	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-122	Titanium heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	None	None	No	Not applicable. There are no in-scope titanium heat exchanger components or piping, piping components exposed to air – indoor uncontrolled or air – outdoor in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-123	Titanium heat exchanger components other than tubes, piping and piping components exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope titanium heat exchanger components other than tubes, or piping and piping components exposed to raw water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-124	Stainless steel, steel (with stainless steel or nickel alloy cladding) spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water >60°C (>140°F), treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. Cracking of stainless steel piping, piping components exposed to treated borated water >60°C (>140°F) is addressed in row 3.3.1-028. Normal spent fuel pool temperature is <60°C (140°F). Spent fuel storage racks are exposed to treated borated water. The associated NUREG-2191 aging items are not used.
3.3.1-125	Stainless steel, steel (with stainless steel cladding), nickel alloy spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.3.1-126	Metallic piping, piping components exposed to treated water, treated borated water, raw water	Wall thinning due to erosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-127	Metallic piping, piping components, tanks exposed to raw water, raw water (potable), treated water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, Open-Cycle Cooling Water System, AMP XI.M27, Fire Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Yes (SRP-SLR Section 3.3.2.2.7)	Consistent with NUREG-2191. Loss of material due to recurring internal corrosion of metallic piping, piping components exposed to raw water in the fire service system is managed by the Fire Water System (B2.1.16) program. Loss of material due to recurring internal corrosion of metallic piping, piping components exposed to raw water in the service water system is managed by the Open-Cycle Cooling Water System (B2.1.11) program (for components covered by NRC GL 89-13) or by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program (for components not covered by NRC GL 89-13). See further evaluation in Section 3.3.2.2.7.
3.3.1-128	Steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete, air, condensation, raw water	Loss of material due to general, pitting, crevice corrosion, MIC (soil, raw water only)	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Not applicable. There are no in-scope steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation, raw water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-130	Metallic sprinklers exposed to air, condensation, raw water, raw water (potable), treated water	Loss of material due to general (where applicable), pitting, crevice corrosion, MIC (except for aluminum, and in raw water, raw water (potable), treated water only); flow blockage due to fouling	AMP XI.M27, Fire Water System	No	Consistent with NUREG-2191. Flow blockage is not an applicable aging effect for components not credited with delivery of downstream flow.
3.3.1-131	Steel, stainless steel, copper alloy, aluminum piping, piping components exposed to air, condensation	Flow blockage due to fouling	AMP XI.M27, Fire Water System	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-132	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, External Surfaces Monitoring of Mechanical Components or AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191. Loss of material of steel components exposed to condensation and cracking of copper alloy (>15% Zn) components exposed to air – indoor uncontrolled or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program.
3.3.1-133	HDPE underground piping, piping components	Cracking, blistering	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope HDPE underground piping, piping components in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-134	Steel, stainless steel, copper alloy piping, piping components, and heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. Flow blockage is not an applicable aging effect for components not credited with delivery of downstream flow.
3.3.1-135	Steel, stainless steel pump casings exposed to waste water environment	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.
3.3.1-136	Steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to general, pitting, crevice corrosion, MIC (raw water, raw water (potable), treated water, soil only)	AMP XI.M27, Fire Water System	No	Not applicable. There are no in-scope steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-137	Steel, stainless steel, aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to treated water, raw water, waste water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191.
3.3.1-138	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water, air-dry, air, condensation	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191.
3.3.1-139	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water, air-dry, air, condensation	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-140	Gray cast iron, ductile iron piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191.
3.3.1-142	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to fuel oil, lubricating oil, treated water, treated borated water, raw water, waste water	Loss of material due to general (steel; copper alloy in raw water, waste water only), pitting, crevice corrosion, MIC (raw water and waste water environments only)	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.3.1-144	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. Cracking of stainless steel tanks exposed to concrete is addressed in row 3.3.1-230. Aging of stainless steel piping exposed to concrete is addressed in row 3.3.1-202. There is no aluminum piping exposed to soil or concrete, and does not have steel piping exposed to a carbonate/bicarbonate soil environment. The associated NUREG-2191 aging items are not used.
3.3.1-145	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Engineered Safety Features (refueling water) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-146	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.3)	Not applicable. There are no in-scope stainless steel underground piping, piping components or tanks in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-147	Nickel alloy, nickel alloy cladding piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191.
3.3.1-149	Fiberglass piping, piping components, ducting, ducting components exposed to air – outdoor	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There are no in-scope fiberglass piping, piping components, ducting, ducting components exposed to air – outdoor in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-150	Fiberglass piping, piping components, ducting, ducting components exposed to air	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There are no in-scope fiberglass piping, piping components, ducting, ducting components exposed to air in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-151	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. Reduction of heat transfer for copper alloy cooling coils exposed to condensation is addressed in row 3.3.1-161. Reduction of heat transfer for stainless steel cooling coils exposed to air – indoor uncontrolled is addressed in row 3.3.1-096a. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-155	Stainless steel piping, piping components, and tanks exposed to waste water >60°C (>140°F)	Cracking due to SCC	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.
3.3.1-157	Steel piping, piping components, heat exchanger components exposed to air-outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M27, Fire Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. Loss of material of steel and gray cast iron components exposed to air-outdoor is addressed in rows 3.3.1-063 and 3.3.1-078. The associated NUREG-2191 aging items are not used.
3.3.1-158	Nickel alloy piping, piping components heat exchanger components (for components not covered by NRC GL 89-13) exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. Loss of material of nickel alloy components exposed to raw water is addressed in row 3.3.1-130. The associated NUREG-2191 aging items are not used.
3.3.1-159	Fiberglass piping, piping components, ducting, ducting components exposed to air	Loss of material due to wear	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope fiberglass piping, piping components, ducting, ducting components exposed to air in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-160	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, raw water, waste water	Cracking due to SCC	AMP XI.M20, Open-Cycle Cooling Water System, AMP XI.M21A, Closed Treated Water Systems, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191 with a different aging management program credited for some components. Cracking of copper alloy (>15% Zn) components exposed to waste water in the diesel generator services system is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Cracking of copper alloy (>15% Zn) components exposed to raw water in the diesel generator services system is managed by the Open-Cycle Cooling Water System (B2.1.11) program. Cracking of copper alloy (>15% Zn) components exposed to closed-cycle cooling water in the diesel generator services system is managed by the Closed Treated Water Systems (B2.1.12) program. Cracking of copper alloy (>15% Zn) components exposed to raw water in the fire service system is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program instead of the Open-Cycle Cooling Water System (B2.1.11) program.
3.3.1-161	Copper alloy heat exchanger tubes exposed to condensation	Reduction of heat transfer due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.
3.3.1-166	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. There are no in-scope copper alloy piping, piping components exposed to concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-167	Zinc piping components exposed to air – indoor controlled, air – indoor uncontrolled	None	None	No	Not applicable. There are no in-scope zinc piping components exposed to air – indoor controlled or air – indoor uncontrolled in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-169	Steel, copper alloy piping, piping components exposed to steam	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.3.1-170	Stainless steel piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.3.1-172	PVC piping, piping components exposed to air-outdoor	Reduction in impact strength due to photolysis	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There are no in-scope PVC piping, piping components exposed to air-outdoor in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-175	Fiberglass piping, piping components, tanks exposed to raw water (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope fiberglass piping, piping components or tanks exposed to raw water (for components not covered by NRC GL 89-13), raw water (potable), treated water or waste water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-176	Fiberglass piping, piping components, tanks exposed to raw water environment (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope fiberglass piping, piping components or tanks exposed to raw water (for components not covered by NRC GL 89-13), raw water (potable), treated water or waste water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-177	Fiberglass piping, piping components exposed to soil	Loss of material due to wear	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope fiberglass piping, piping components exposed to soil in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-178	Fiberglass piping and piping components exposed to concrete	None	None	No	Not applicable. There are no in-scope fiberglass piping and piping components exposed to concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-179	Masonry walls: structural fire barriers exposed to air	Cracking due to restraint shrinkage, creep, aggressive environment; loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.M26, Fire Protection, and AMP XI.S5, Masonry Walls	No	Consistent with NUREG-2191. No Auxiliary Systems components are aligned to this item. Only components in Structures and Component Supports (Turbine Building and Circulating Water Intake Structure) are aligned to this item.
3.3.1-181	Titanium piping, piping components exposed to condensation	None	None	No	Not applicable. There are no in-scope titanium piping, piping components exposed to condensation in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-182	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.
3.3.1-184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. There are no in-scope PVC piping, piping components or tanks exposed to concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-185	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Cracking due to SCC	AMP XI.M27, Fire Water System	No	Not applicable. There are no in-scope aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), or treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-186	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, or waste water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-189	Aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), waste water	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.8)	Consistent with NUREG-2191. Cracking of aluminum components exposed to air – indoor uncontrolled and air – outdoor is managed by the One-Time Inspection (B2.1.20) program. Cracking of aluminum trap body in the instrument air system exposed to waste water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. See further evaluation in Section 3.3.2.2.8.
3.3.1-192	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no in-scope aluminum underground piping, piping components, tanks in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-193	Steel components exposed to treated water, raw water, raw water (potable), waste water	Long-term loss of material due to general corrosion	AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-194	PVC piping, piping components, and tanks exposed to soil	Loss of material due to wear	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope PVC piping, piping components, and tanks exposed to soil in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-195	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling (raw water only)	AMP XI.M27, Fire Water System	No	Not applicable. There are no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, or cementitious piping, piping components exposed to raw water, treated water, or raw water (potable) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-196	HDPE piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking, blistering; flow blockage due to fouling (raw water only)	AMP XI.M27, Fire Water System	No	Not applicable. There are no in-scope HDPE piping, piping components exposed to raw water, treated water, or raw water (potable) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-197	Metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a leakage boundary (spatial) or structural integrity (attached) intended function exposed to any external environment except soil, concrete	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. External loss of material of metallic fire water system components with only a leakage boundary (spatial) or structural integrity (attached) intended function exposed to any external environment except soil or concrete is addressed in row 3.3.1-078. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-198	Metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a leakage boundary (spatial) or structural integrity (attached) intended function	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC (all metallic materials except aluminum; in liquid environments only)	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. Internal loss of material of metallic fire water system components with only a leakage boundary (spatial) intended function exposed to a raw water internal environment is addressed in rows 3.3.1-064. The associated NUREG-2191 aging items are not used.
3.3.1-199	Cranes: steel structural bolting exposed to air	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	AMP XI.M23, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	No	Consistent with NUREG-2191.
3.3.1-202	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.3.2.2.9.
3.3.1-203	Stainless steel; steel with stainless steel cladding, nickel alloy piping, piping components, heat exchanger components, tanks exposed to treated water, sodium pentaborate solution	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-205	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. Cracking of stainless steel piping, piping components and tanks exposed to air – outdoor or condensation is managed by the One-Time Inspection (B2.1.20) program. Cracking of the stainless steel reactor makeup water storage tank exposed to air – outdoor is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program. See further evaluation in Section 3.3.2.2.3.
3.3.1-207	Stainless steel, copper alloy, titanium heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope titanium heat exchanger tubes, and has no stainless steel or copper alloy heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13) with a heat transfer function in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-208	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, or cementitious piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-210	HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking, blistering; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-214	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Not applicable. There are no in-scope copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-215	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion	AMP XI.M27, Fire Water System	No	Not applicable. There are no in-scope aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), or treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-216	Stainless steel fire water storage tanks exposed to air, condensation, soil, concrete	Cracking due to SCC	AMP XI.M27, Fire Water System	No	Not applicable. There are no in-scope stainless steel fire water storage tanks exposed to air, condensation, soil, or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-218	Stainless steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion, MIC (water and soil environment only)	AMP XI.M27, Fire Water System	No	Not applicable. There are no in-scope stainless steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), or treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-219	Stainless steel piping, piping components exposed to steam	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-222	Stainless steel, nickel alloy tanks exposed to air, condensation (internal/external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. Loss of material of stainless steel CRDM cooling water chemical feed tank exposed to air – indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.4.
3.3.1-223	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no in-scope aluminum underground piping, piping components, or tanks in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-226	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Not applicable. There are no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-227	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-228	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.4)	Not applicable. Loss of material of stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air is addressed in row 3.3.1-232. There are no nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-229	Stainless steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191.
3.3.1-230	Stainless steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-231	Stainless steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.3)	Not applicable. Cracking of stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air is addressed in row 3.3.1-205. The associated NUREG-2191 aging items are not used.
3.3.1-232	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. Loss of material of stainless steel components exposed to air – outdoor or condensation is managed by the One-Time Inspection (B2.1.20) program. Loss of material of the stainless steel reactor makeup water storage tank in the reactor makeup water supply system exposed to air – outdoor is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program. See further evaluation in Section 3.3.2.2.4.
3.3.1-233	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. Cracking of aluminum components exposed to air – indoor uncontrolled and air – outdoor is addressed in row 3.3.1-189. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-234	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.10)	Consistent with NUREG-2191. Loss of material of aluminum components exposed to air – indoor uncontrolled and air – outdoor is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.10.
3.3.1-235	Metallic piping, piping components exposed to air-dry (internal)	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M24, Compressed Air Monitoring	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Steam and Power Conversion Systems (emergency feedwater, feedwater, and main steam) are aligned to this item.
3.3.1-236	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope titanium heat exchanger tubes exposed to treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-237	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not applicable. There are no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-238	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope titanium heat exchanger tubes exposed to closed-cycle cooling water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-239	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not applicable. There are no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-240	Aluminum heat exchanger components exposed to waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. Loss of material of aluminum components exposed to waste water is addressed in row 3.3.1-247. The associated NUREG-2191 aging items are not used.
3.3.1-241	Stainless steel, nickel alloy heat exchanger components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. Loss of material of stainless steel heat exchanger components exposed to air – indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.4.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-242	Aluminum heat exchanger components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. Loss of material of aluminum components exposed to air – indoor uncontrolled and air – outdoor is addressed in row 3.3.1-234. The associated NUREG-2191 aging items are not used.
3.3.1-244	Stainless steel, nickel alloy piping, piping components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.3.1-245	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. Loss of material of aluminum components exposed to air – indoor uncontrolled and air – outdoor is addressed in row 3.3.1-234. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-246	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.4)	Not applicable. There are no in-scope stainless steel or nickel alloy underground piping, piping components, or tanks in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-247	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.10)	Consistent with NUREG-2191. Loss of material of aluminum components exposed to waste water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. See further evaluation in Section 3.3.2.2.10.
3.3.1-248	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. Boric acid corrosion is not an applicable aging effect for aluminum piping, piping components, so air with borated water leakage environment is not assigned to these materials. The associated NUREG-2191 aging items are not used.
3.3.1-249	Steel heat exchanger tubes internal to components exposed to air-outdoor, air-indoor uncontrolled, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-250	Steel reactor coolant pump oil collection system tanks, piping, piping components exposed to lubricating oil (waste oil)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope steel reactor coolant pump oil collection system tanks, piping, piping components exposed to lubricating oil (waste oil) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-252	Aluminum piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope aluminum piping, piping components exposed to soil or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-253	PVC piping, piping components exposed to raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water only)	AMP XI.M20, Open-Cycle Cooling Water System, AMP XI.M27, Fire Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope PVC piping, piping components exposed to raw water, raw water (potable), treated water, or waste water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-254	Aluminum heat exchanger components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no in-scope aluminum heat exchanger components exposed to air or condensation in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-255	Any material fire damper assemblies exposed to air	Loss of material due to general, pitting, crevice corrosion; cracking due to SCC; hardening, loss of strength, shrinkage due to elastomer degradation	AMP XI.M26, Fire Protection	No	Consistent with NUREG-2191. Cracking, hardening, loss of strength, and shrinkage are not applicable aging effects for steel fire damper assemblies.
3.3.1-257	Steel, stainless steel, copper alloy heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.3.1-258	Metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water	Flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. Flow blockage of stainless steel, steel, and gray cast iron components exposed to waste water is addressed in rows 3.3.1-091, and 3.3.1-095. The associated NUREG-2191 aging items are not used.
3.3.1-259	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope aluminum piping, piping components exposed to raw water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-260	Metallic HVAC closure bolting exposed to air, condensation	Loss of material due to general (where applicable), pitting, crevice corrosion; cracking due to SCC, loss of preload	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.
3.3.1-261	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed-cycle cooling water, raw water	Cracking due to SCC	AMP XI.M20, Open-Cycle Cooling Water System, or AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed-cycle cooling water or raw water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-262	Titanium piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Cracking due to SCC	AMP XI.M20, Open-Cycle Cooling Water System, or AMP XI.M21A, Closed Treated Water Systems, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope titanium piping, piping components, or heat exchanger components exposed to closed-cycle cooling water or treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-263	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. Hardening or loss of strength, loss of material, and cracking or blistering of polymeric components exposed to air – indoor uncontrolled (external) is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. Hardening or loss of strength, loss of material, and cracking or blistering of polymeric components exposed to treated water or waste water (internal) is managed by the Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.
3.3.1-265	Steel heat exchanger radiator tubes exposed to fuel oil	Reduction of heat transfer due to fouling	AMP XI.M30, Fuel Oil Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope steel heat exchanger radiator tubes exposed to fuel oil in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-266	Steel heat exchanger radiator tubes exposed to fuel oil	Reduction of heat transfer due to fouling	AMP XI.M30, Fuel Oil Chemistry	No	Not applicable. There are no in-scope steel heat exchanger radiator tubes exposed to fuel oil in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-267	Subliming compound fireproofing/fire barriers (Thermolag®, Darmatt™, 3M™ Interam™, and other similar materials) exposed to air	Loss of material due to abrasion, flaking, vibration; cracking/delamination due to chemical reaction, settlement; change in material properties due to gamma irradiation exposure; separation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. No Auxiliary Systems components are aligned to this item. Only components in Structures and Component Supports (miscellaneous structural commodities) are aligned to this item.
3.3.1-268	Cementitious coating fireproofing/fire barriers (Pyrocrete, BIO™, K-10 Mortar, Cafecote, and other similar materials) exposed to air	Loss of material due to abrasion, exfoliation, elevated temperature, flaking, spalling; cracking/delamination due to chemical reaction, elevated temperature, settlement, vibration; change in material properties due to elevated temperature, gamma irradiation exposure; separation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. No Auxiliary Systems components are aligned to this item. Only components in Structures and Component Supports (miscellaneous structural commodities) are aligned to this item.
3.3.1-269	Silicate fireproofing/fire barriers (Marinite®, Kaowool™, Cerafiber®, Cera® blanket, or other similar materials) exposed to air	Loss of material due to abrasion, flaking; cracking/delamination due to settlement; change in material properties due to gamma irradiation exposure; separation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. No Auxiliary Systems components are aligned to this item. Only components in Structures and Component Supports (miscellaneous structural commodities) are aligned to this item.

Results Tables: Auxiliary Systems AMR Results

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Accumulator (control room isolation damper backup air)	PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
Air handling unit (battery room cooling coil and fin)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A
Air handling unit (battery room cooling coil header)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (battery room cooling drip pan)	PB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (battery room filter, cooler, damper, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
						VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A
						VII.F2.A-08	3.3.1-090	A
Air handling unit (BOP charger area cooling coil header)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (BOP charger area cooling coil)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Air handling unit (BOP charger area drip pan)	LB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Air handling unit (charging/SI pump room cooling coil and fin)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A
Air handling unit (charging/SI pump room cooling coil header)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (charging/SI pump room drip pan)	PB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (charging/SI pump room filter, cooler, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A
Air handling unit (computer room cooling coil header)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (computer room cooling coil)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Air handling unit (computer room cooling drip pan)	LB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Air handling unit (control rod position data cabinet cooling coil header)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (control rod position data cabinet cooling coil)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Air handling unit (control rod position data cabinet cooling drip pan)	LB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (control room cooling coil and fin)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A
Air handling unit (control room cooling coil header)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (control room cooling drip pan)	PB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (control room filter, cooler, damper, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Air handling unit (controlled access cooling coil header)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (controlled access cooling coil)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Air handling unit (controlled access cooling drip pan)	LB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (CRDM switchgear room cooling coil header)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (CRDM switchgear room cooling coil)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Air handling unit (CRDM switchgear room drip pan)	LB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (emergency feedwater pump area cooling coil and fin)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A
Air handling unit (emergency feedwater pump area cooling coil header)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Air handling unit (emergency feedwater pump area drip pan)	PB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (emergency feedwater pump area filter, cooler, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A
Air handling unit (ESF switchgear room cooling coil and fin)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A
Air handling unit (ESF switchgear room cooling coil header)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (ESF switchgear room drip pan)	PB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (ESF switchgear room filter, cooler, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A
Air handling unit (Fuel Handling Building supplemental cooling coil header)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Air handling unit (Fuel Handling Building supplemental cooling coil)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Air handling unit (Fuel Handling Building supplemental cooling drip pan)	LB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-781a	3.3.1-094a	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-99a	3.3.1-094	A
Air handling unit (MCC switchgear cooling coil and fin)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A
Air handling unit (MCC switchgear drip pan)	PB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (MCC switchgear filter, cooler, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A
Air handling unit (MCC switchgear filter, cooling coil header)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (Reactor Building cooling unit - cooling coil and fin)	HT;PB	Copper alloy	(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Air handling unit (Reactor Building cooling unit - cooling coil header)	PB	Copper alloy	(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-179	3.3.1-038	A
Air handling unit (Reactor Building cooling unit - filter, damper, cooler, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A
Air handling unit (relay room cooling coil and fin)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A
Air handling unit (relay room cooling coil header)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (relay room cooling drip pan)	PB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (relay room filter, cooler, damper, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A
Air handling unit (RHR/spray pump room cooling coil and fin)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Air handling unit (RHR/spray pump room drip pan)	PB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (RHR/spray pump room filter, cooler, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A
Air handling unit (RHR/spray pump room filter, cooling coil header)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (SAS/computer room cooling coil header)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (SAS/computer room cooling coil)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Air handling unit (SAS/computer room cooling drip pan)	LB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (service water booster pump area cooling coil and fin)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Air handling unit (service water booster pump area cooling coil header)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (service water booster pump area drip pan)	PB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (service water booster pump area filter, cooler, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A
Air handling unit (speed switch room cooling coil and fin)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-565	3.3.1-161	A
Air handling unit (speed switch room cooling coil header)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Air handling unit (speed switch room drip pan)	PB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Air handling unit (speed switch room filter, cooler, and fan plenum)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-08	3.3.1-090	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Damper housing	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-781a	3.3.1-094a	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-99a	3.3.1-094	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-781a	3.3.1-094a	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-99a	3.3.1-094	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Duct	FB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-781a	3.3.1-094a	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-99a	3.3.1-094	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-781a	3.3.1-094a	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-99a	3.3.1-094	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Expansion joint	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-504	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.AP-103	3.3.1-096	A
Fan housing (battery room exhaust)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fan housing (control room emergency filtration)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
Fan housing (diesel generator room)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
Fan housing (Fuel Handling Building)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
Fan housing (service water pump house)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
Filter housing (Auxiliary Building)	SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Filter housing (control room)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
Filter housing (Fuel Handling Building)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Filter rack	SS	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-781a	3.3.1-094a	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-99a	3.3.1-094	A
Fire damper assembly	FB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Fire Protection (B2.1.15)	VII.G.A-789	3.3.1-255	A
			(I) Air – indoor uncontrolled	Loss of material	Fire Protection (B2.1.15)	VII.G.A-789	3.3.1-255	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Heat exchanger (CRDM cooler - cooling coil)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Heat exchanger (CRDM cooler - drip pan)	LB	Stainless steel	(E) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (CRDM cooler - header)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Heater coil housing	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Humidifier reservoir	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A
					Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A

Table 3.3.2-1 Auxiliary Systems - Air Handling and Local Ventilation and Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
HVAC bolting	FB;LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Loss of material; cracking; loss of preload	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-794	3.3.1-260	A
		Steel	(E) Air – indoor uncontrolled	Loss of material; cracking; loss of preload	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-794	3.3.1-260	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Condensation	Loss of material; cracking; loss of preload	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-794	3.3.1-260	A
Piping, piping components	PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Valve body	PB;SI	Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-1 Plant-Specific Notes: None

Table 3.3.2-2 Auxiliary Systems - Auxiliary Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (CRDM cooling water)	LB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Tank (CRDM cooling water chemical feed)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-751b	3.3.1-222	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-2 Auxiliary Systems - Auxiliary Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (CRDM cooling water expansion)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-2 Plant-Specific Notes: None

Table 3.3.2-3 Auxiliary Systems - Boron Recycle - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Demineralizer shell	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Eductor	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-3 Auxiliary Systems - Boron Recycle - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.E.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Heat exchanger (concentrates sample cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (concentrates sample cooler - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-189	3.3.1-046	A

Table 3.3.2-3 Auxiliary Systems - Boron Recycle - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (concentrates sample cooler - tube and tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (distillate cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-85	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.F.SP-85	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Heat exchanger (distillate cooler - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (distillate cooler - tube and tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-85	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.F.SP-85	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Heat exchanger (evaporator - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A

Table 3.3.2-3 Auxiliary Systems - Boron Recycle - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (evaporator - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (evaporator condenser - channel)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-189	3.3.1-046	A
Heat exchanger (evaporator condenser - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-85	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.F.SP-85	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Heat exchanger (evaporator condenser - tube and tubesheet)	PB	Stainless steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(E) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-85	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.F.SP-85	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Heat exchanger (evaporator feed preheater - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C

Table 3.3.2-3 Auxiliary Systems - Boron Recycle - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (evaporator feed preheater - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (evaporator vent condenser - channel)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-189	3.3.1-046	A
Heat exchanger (evaporator vent condenser - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-85	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.F.SP-85	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Heat exchanger (evaporator vent condenser - tube and tubesheet)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-3 Auxiliary Systems - Boron Recycle - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.E.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Piping, piping components (chemical addition)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1

Table 3.3.2-3 Auxiliary Systems - Boron Recycle - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (evaporator concentrates)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Pump casing (evaporator distillate)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (evaporator feed)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Rupture disc	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.E.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Treated water	None	None	VII.J.AP-51	3.3.1-117	A
Sight glass (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-3 Auxiliary Systems - Boron Recycle - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (evaporator reagent)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Tank (recycle hold-up)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Trap body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.E.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-3 Auxiliary Systems - Boron Recycle - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body (chemical addition)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1

Table 3.3.2-3 Plant-Specific Notes:

1. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program has been substituted for the Water Chemistry (B2.1.2) program and the One-Time Inspection (B2.1.20) program to manage the applicable aging effects for chemical treatment components.

Table 3.3.2-4 Auxiliary Systems - Building Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
Valve body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A

Table 3.3.2-4 Plant-Specific Notes: None

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Blender	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Bolting	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Demineralizer shell	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Filter housing	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Filter housing (boric acid)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Filter housing (charging pump lubricating oil)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
Filter housing (seal injection)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Filter housing (seal return)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flexible hose	LB;PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Treated water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A
		Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Flow element	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Gearbox / oil sump (charging pump)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
Heat exchanger (charging pump oil - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (charging pump oil - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	C
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	C

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (charging pump oil - tube)	HT;PB	Stainless steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	C
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	C
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	VII.E1.A-791	3.3.1-257	A
					One-Time Inspection (B2.1.20)	VII.E1.A-791	3.3.1-257	A
Heat exchanger (charging pump oil - tubesheet)	PB	Stainless steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	C
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	C
Heat exchanger (excess letdown - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (excess letdown - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (excess letdown - tube)	HT;PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (excess letdown - tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (letdown - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (letdown - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (letdown - tube)	HT;PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Treated borated water >60°C (>140°F)	Cracking	Water Chemistry (B2.1.2)	VII.E1.A-69	3.3.1-003	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A
Heat exchanger (letdown - tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (regenerative - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (regenerative - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (regenerative - tube)	HT;PB	Stainless steel	(E) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A
			(I) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A
Heat exchanger (regenerative - tubesheet)	PB	Stainless steel	(E) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
			(I) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (seal water - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (seal water - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (seal water - tube)	HT;PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A
Heat exchanger (seal water - tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Insulation (containment penetration)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.E-24	3.2.1-005	A; 1
						VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-133	3.3.1-099	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-408	3.4.1-060	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.E1.A-407	3.3.1-126	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.E1.A-407	3.3.1-126	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(I) Treated water	Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
						VIII.B1.S-408	3.4.1-060	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Piping, piping components (Class 1 <NPS 4)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Reactor coolant	Cracking	ASME Code Class 1 Small-Bore Piping (B2.1.22)	IV.C2.RP-235	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-235	3.1.1-039	A
					Water Chemistry (B2.1.2)	IV.C2.RP-235	3.1.1-039	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.E1.A-407	3.3.1-126	A
Pulsation dampener (alternate seal injection)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (alternate seal injection)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Pump casing (boric acid)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Pump casing (charging pump lubricating oil)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
Pump casing (charging)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-115	3.3.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Sight glass	LB;PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Lubricating oil	None	None	VII.J.AP-15	3.3.1-117	A
			(I) Treated borated water	None	None	VII.J.AP-52	3.3.1-117	A

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass (body)	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
Tank (boric acid batch - steam jacket)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	C
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	C
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	C
Tank (boric acid batch)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Tank (boric acid)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Tank (chemical mixing)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	C
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	C

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (resin fill)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	C
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	C
Tank (volume control)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C

Table 3.3.2-5 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Valve body (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-09	3.1.1-033	C
					Water Chemistry (B2.1.2)	IV.C2.R-09	3.1.1-033	C
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.3.2-5 Plant-Specific Notes:

1. Erosion line item applies to charging pump miniflow orifices.

Table 3.3.2-6 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Compressor housing (chiller)	PB	Gray cast iron	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Eductor (chilled water lubrication system)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.C2.AP-127	3.3.1-097	A
Filter housing (lube oil)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C2.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.C2.AP-138	3.3.1-100	A
Filter housing (refrigerant)	PB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
Flow Element	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Heat exchanger (A and B chilled water condenser - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	C

Table 3.3.2-6 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (A and B chilled water condenser - fins)	HT	Stainless steel	(E) Gas	None	None	VII.J.AP-22	3.3.1-120	C
Heat exchanger (A and B chilled water condenser - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C
Heat exchanger (A and B chilled water condenser - tube)	HT;PB	Stainless steel	(E) Gas	None	None	VII.J.AP-22	3.3.1-120	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	C
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	A
Heat exchanger (A and B chilled water condenser - tubesheet)	PB	Stainless steel	(E) Gas	None	None	VII.J.AP-22	3.3.1-120	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	C
Heat exchanger (A and B chilled water evaporator - channel)	PB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
Heat exchanger (A and B chilled water evaporator - fins)	HT	Copper alloy	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	A
Heat exchanger (A and B chilled water evaporator - shell)	PB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C

Table 3.3.2-6 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (A and B chilled water evaporator - tube)	HT;PB	Copper alloy	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	C
Heat exchanger (A and B chilled water evaporator - tubesheet)	PB	Steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C
Heat exchanger (C chilled water condenser - channel)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C1.A-414	3.3.1-139	A
Heat exchanger (C chilled water condenser - fins)	HT	Copper alloy	(E) Gas	None	None	VII.J.AP-9	3.3.1-114	C
Heat exchanger (C chilled water condenser - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C
Heat exchanger (C chilled water condenser - tube)	HT;PB	Copper alloy	(E) Gas	None	None	VII.J.AP-9	3.3.1-114	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-179	3.3.1-038	A
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	A

Table 3.3.2-6 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (C chilled water condenser - tubesheet)	PB	Steel	(E) Gas	None	None	VII.J.AP-6	3.3.1-121	C
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-183	3.3.1-038	A
Heat exchanger (C chilled water evaporator - channel)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (C chilled water evaporator - fins)	HT	Copper alloy	(E) Gas	None	None	VII.J.AP-9	3.3.1-114	C
Heat exchanger (C chilled water evaporator - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C
Heat exchanger (C chilled water evaporator - tube)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	A
			(E) Gas	None	None	VII.J.AP-9	3.3.1-114	C
Heat exchanger (C chilled water evaporator - tubesheet)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(E) Gas	None	None	VII.J.AP-6	3.3.1-121	C
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-6 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A; 1
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.C2.AP-127	3.3.1-097	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-73	3.4.1-014	E, 2
Pump casing (chemical feed)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2

Table 3.3.2-6 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (chilled water)	PB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
Pump casing (fluid ejector)	PB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
		Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Pump casing (lube oil)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.C2.AP-127	3.3.1-097	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.C2.AP-127	3.3.1-097	A
Sight glass	LB;PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Gas	None	None	VII.J.AP-98	3.3.1-117	A
			(I) Treated water	None	None	VII.J.AP-51	3.3.1-117	A

Table 3.3.2-6 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass (body)	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Strainer body (chemical feed pump suction)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Tank (chemical feed)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-162	3.4.1-083	E, 2
Tank (chilled water expansion)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
Tank (chiller purge unit)	PB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	C
		Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C

Table 3.3.2-6 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (lube oil sump)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C2.AP-127	3.3.1-097	C
					One-Time Inspection (B2.1.20)	VII.C2.AP-127	3.3.1-097	C

Table 3.3.2-6 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.C2.AP-127	3.3.1-097	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-73	3.4.1-014	E, 2

Table 3.3.2-6 Plant-Specific Notes:

1. Closed-cycle cooling water is a subset of treated water per NUREG-2191, Section IX.D, and therefore this GALL line item is applicable for erosion.

2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program has been substituted for the Water Chemistry (B2.1.2) and the One-Time Inspection (B2.1.20) programs to manage the applicable aging effects for chemical treatment components.

Table 3.3.2-7 Auxiliary Systems - Circulating Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Steel	(E) Raw water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Piping, piping components	PB	Steel	(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Traveling screen element	FLT	Stainless steel	(E) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	A
Valve body	PB	Gray cast iron	(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-7 Plant-Specific Notes: None

Table 3.3.2-8 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Accumulator	SI	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Filter housing	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
Flexible hose	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Flow element	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-8 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (component cooling - channel)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C1.A-414	3.3.1-139	A
Heat exchanger (component cooling - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (component cooling - tube)	HT;PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	C
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	A
Heat exchanger (component cooling - tubesheet)	PB	Steel with internal coating	(E) Closed-cycle cooling water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C2.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C2.A-414	3.3.1-139	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C1.A-414	3.3.1-139	A

Table 3.3.2-8 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (pump motor cooler - channel)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C2.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C2.A-414	3.3.1-139	A
Heat exchanger (pump motor cooler - fins)	HT	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.A-451a	3.3.1-189	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-763a	3.3.1-234	C
				Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-419	3.3.1-096a	A
Heat exchanger (pump motor cooler - tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
				Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-419	3.3.1-096a	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	A
Heat exchanger (pump motor cooler - tubesheet)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Oil trap	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-8 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
		Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A; 2
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Pump casing (chemical injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1

Table 3.3.2-8 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (component cooling booster)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Pump casing (component cooling drain tank)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Pump casing (component cooling)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
Tank (chemical injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-162	3.4.1-083	E, 1
Tank (component cooling drain)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-8 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (component cooling surge)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C2.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C2.A-414	3.3.1-139	A
Valve body	LB;PB;SI	Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.3.2-8 Plant-Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program has been substituted for the Water Chemistry (B2.1.2) and the One-Time Inspection (B2.1.20)programs to manage the applicable aging effects for chemical treatment components.

2. Closed-cycle cooling water is a subset of treated water per NUREG-2191, Section IX.D, and therefore this GALL line item is applicable for erosion.

Table 3.3.2-9 Auxiliary Systems - Demineralized Water - Nuclear Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Valve body	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
					Selective Leaching (B2.1.21)	VIII.E.SP-55	3.4.1-033	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-9 Plant-Specific Notes: None

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Accumulator (air start positive shutdown)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Air dryer (separator and piping)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-241	3.3.1-109	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Expansion joint	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-504	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.AP-103	3.3.1-096	A
			(I) Closed-cycle cooling water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.AP-259	3.3.1-085	A
Expansion joint (flange and bellows)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Diesel exhaust	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-128	3.3.1-083	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Expansion joint (tube)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Diesel exhaust	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
Filter housing (fuel oil)	PB;SI	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A
		Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A
Filter housing (lube oil)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Filter silencer body	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Flame arrestor	PB	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-763a	3.3.1-234	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-763a	3.3.1-234	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.H2.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-763a	3.3.1-234	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flexible hose	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Closed-cycle cooling water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.AP-259	3.3.1-085	A
			(I) Condensation	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-504	3.3.1-085	A
			(I) Lubricating oil	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-677	3.3.1-085	A
			(I) Raw water	Hardening or loss of strength; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-75	3.3.1-085	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-76	3.3.1-096	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-136	3.3.1-071	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-136	3.3.1-071	A
Heat exchanger (intercooler - channel cover)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Heat exchanger (intercooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-55	3.3.1-040	C
Heat exchanger (intercooler - cover liner)	PB	Stainless steel	(E) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-55	3.3.1-040	C

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (intercooler - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (intercooler - tube)	HT;PB	Copper alloy (>15% Zn)	(E) Closed-cycle cooling water	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.A-473a	3.3.1-160	A
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
					Selective Leaching (B2.1.21)	VII.H2.AP-43	3.3.1-072	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	A
			(I) Raw water	Cracking	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-66	3.3.1-072	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-193	3.3.1-034	C
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-187	3.3.1-042	A
Heat exchanger (intercooler - tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water >60°C (>140°F)	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-186	3.3.1-043	C
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-55	3.3.1-040	C
Heat exchanger (jacket water - channel cover)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Heat exchanger (jacket water - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-55	3.3.1-040	C
Heat exchanger (jacket water - cover liner)	PB	Stainless steel	(E) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-55	3.3.1-040	C
Heat exchanger (jacket water - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (jacket water - tube)	HT;PB	Copper alloy (>15% Zn)	(E) Closed-cycle cooling water	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.A-473a	3.3.1-160	A
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
					Selective Leaching (B2.1.21)	VII.H2.AP-43	3.3.1-072	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	A
			(I) Raw water	Cracking	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-193	3.3.1-034	C
					Selective Leaching (B2.1.21)	VII.C1.A-66	3.3.1-072	A
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-187	3.3.1-042	A
Heat exchanger (jacket water - tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water >60°C (>140°F)	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-186	3.3.1-043	C
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-55	3.3.1-040	C
Heat exchanger (lube oil - channel cover)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Heat exchanger (lube oil - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-55	3.3.1-040	C
Heat exchanger (lube oil - cover liner)	PB	Stainless steel	(E) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-55	3.3.1-040	C
Heat exchanger (lube oil - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-131	3.3.1-098	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-131	3.3.1-098	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (lube oil - tube)	HT;PB	Copper alloy (>15% Zn)	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	C
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	C
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	VII.H2.A-791	3.3.1-257	A
					One-Time Inspection (B2.1.20)	VII.H2.A-791	3.3.1-257	A
			(I) Raw water	Cracking	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-473b	3.3.1-160	A
				Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-193	3.3.1-034	C
					Selective Leaching (B2.1.21)	VII.C1.A-66	3.3.1-072	A
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-187	3.3.1-042	A
Heat exchanger (lube oil - tubesheet)	PB	Stainless steel	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-138	3.3.1-100	C
					One-Time Inspection (B2.1.20)	VII.H2.AP-138	3.3.1-100	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-55	3.3.1-040	C
Heater housing (keep warm)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heater housing (lube oil)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Manometer	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Condensation	None	None	VII.J.AP-97	3.3.1-117	A
Manometer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-26	3.3.1-055	A
Moisture separator	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-26	3.3.1-055	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Muffler	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Diesel exhaust	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
Oil separator	SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Orifice	PB;RF	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Closed-cycle cooling water >60°C (>140°F)	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-186	3.3.1-043	A
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Piping, piping components	LB;PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water >60°C (>140°F)	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-186	3.3.1-043	A
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-136	3.3.1-071	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-136	3.3.1-071	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-26	3.3.1-055	A
			(I) Diesel exhaust	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
			(E) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-194	3.3.1-037	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-198	3.3.1-109	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (fuel oil transfer)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (fuel oil)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A
Pump casing (intercooler)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	A
Pump casing (jacket water)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	A
Pump casing (keep warm)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	A
Pump casing (lube oil filter)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Pump casing (lube oil)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Pump casing (rocker arm)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass	LB;PB	Glass	(I) Air – dry	None	None	VII.J.AP-48	3.3.1-117	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Closed-cycle cooling water	None	None	VII.J.AP-166	3.3.1-117	A
			(I) Condensation	None	None	VII.J.AP-97	3.3.1-117	A
			(I) Lubricating oil	None	None	VII.J.AP-15	3.3.1-117	A
			(I) Waste water	None	None	VII.J.AP-277	3.3.1-119	A
Sight glass (body)	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A
			(I) Waste water	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-473c	3.3.1-160	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A
Strainer element	FLT	Stainless steel	(E) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-136	3.3.1-071	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-136	3.3.1-071	A
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-138	3.3.1-100	A
Tank (fuel oil day)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A
Tank (fuel oil storage)	PB	Steel	(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-198	3.3.1-109	A
Tank (jacket water head)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	A
Tank (rocker arm lube oil)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Tank (starting air)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Trap body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-26	3.3.1-055	A
Valve body	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(E) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Closed-cycle cooling water	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.A-473a	3.3.1-160	A
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	A
					Selective Leaching (B2.1.21)	VII.H2.AP-43	3.3.1-072	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water >60°C (>140°F)	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-186	3.3.1-043	A
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-136	3.3.1-071	A

Table 3.3.2-10 Auxiliary Systems - Diesel Generator Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Stainless steel	(I) Fuel oil	Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-136	3.3.1-071	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-138	3.3.1-100	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-55	3.3.1-040	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	A
			(E) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.H2.AP-194	3.3.1-037	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-10 Plant-Specific Notes: None

Table 3.3.2-11 Auxiliary Systems - Domestic Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Eyewash - safety shower (stanchion)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-270	3.3.1-088	A
Eyewash - safety shower (valve body)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-47	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-270	3.3.1-088	A
Piping, piping components	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-270	3.3.1-088	A

Table 3.3.2-11 Auxiliary Systems - Domestic Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (hot water recirculating)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
Tank (hot water)	LB	Steel with internal lining	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C1.A-414	3.3.1-139	A
Valve body	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
Waterhammer arrestor	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-270	3.3.1-088	A

Table 3.3.2-11 Plant-Specific Notes: None

Table 3.3.2-12 Auxiliary Systems - Excess Liquid Waste - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Waste water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Demineralizer shell	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Flexible hose	LB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Waste water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-728	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-550	3.3.1-096	A
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-12 Auxiliary Systems - Excess Liquid Waste - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (excess liquid waste)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (radwaste demineralizer booster)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (sump)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Waste water	None	None	VII.J.AP-277	3.3.1-119	A
Sight glass (body)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-12 Auxiliary Systems - Excess Liquid Waste - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (decontamination pit collection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (excess waste hold-up)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-12 Plant-Specific Notes: None

Table 3.3.2-13 Auxiliary Systems - Fire Service - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Stainless steel	(E) Raw water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Raw water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-241	3.3.1-109	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Exhaust silencer	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Diesel exhaust	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
Flame arrestor	PB	Steel	(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Flexible hose	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-132	3.3.1-069	A
					One-Time Inspection (B2.1.20)	VII.G.AP-132	3.3.1-069	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Diesel exhaust	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-128	3.3.1-083	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	A

Table 3.3.2-13 Auxiliary Systems - Fire Service - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger coil (carbon dioxide tank)	PB	Copper alloy	(E) Gas	None	None	VII.J.AP-9	3.3.1-114	C
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	C
Hose reel (fitting)	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	A, 2
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
Hydrant	PB	Gray cast iron	(E) Air – outdoor	Loss of material	Fire Water System (B2.1.16)	VII.G.AP-149	3.3.1-063	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-149	3.3.1-063	A
			(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-198	3.3.1-109	A
Odorizer	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	A
Piping, piping components	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(E) Air – outdoor	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-132	3.3.1-069	A
					One-Time Inspection (B2.1.20)	VII.G.AP-132	3.3.1-069	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A

Table 3.3.2-13 Auxiliary Systems - Fire Service - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Ductile iron with internal lining	(I) Raw water	Loss of coating or lining integrity; loss of material or cracking (for cementitious coatings/linings)	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-416	3.3.1-138	A
Piping, piping components	LB;PB	Ductile iron with internal lining	(I) Raw water	Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-414	3.3.1-139	A
Piping, piping components	LB;PB	Ductile iron with internal lining	(I) Raw water	Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-415	3.3.1-140	A
Piping, piping components	LB;PB	Ductile iron with internal lining	(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
Piping, piping components	LB;PB	Ductile iron with internal lining	(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-198	3.3.1-109	A
Piping, piping components	LB;PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Piping, piping components	LB;PB	Gray cast iron	(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
Piping, piping components	LB;PB	Gray cast iron	(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
Piping, piping components	LB;PB	Gray cast iron	(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A
Piping, piping components	LB;PB	Gray cast iron	(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A, 5
Piping, piping components	LB;PB	Gray cast iron	(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-198	3.3.1-109	A, 5
Piping, piping components	LB;PB	Gray cast iron with internal lining	(I) Raw water	Loss of coating or lining integrity; loss of material or cracking (for cementitious coatings/linings)	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-416	3.3.1-138	A
Piping, piping components	LB;PB	Gray cast iron with internal lining	(I) Raw water	Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-414	3.3.1-139	A
Piping, piping components	LB;PB	Gray cast iron with internal lining	(I) Raw water	Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-415	3.3.1-140	A
Piping, piping components	LB;PB	Gray cast iron with internal lining	(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A, 5
Piping, piping components	LB;PB	Gray cast iron with internal lining	(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-198	3.3.1-109	A, 5
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – outdoor	Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A

Table 3.3.2-13 Auxiliary Systems - Fire Service - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless steel	(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-136	3.3.1-071	A
					One-Time Inspection (B2.1.20)	VII.G.AP-136	3.3.1-071	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	A
				Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 4
					Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Diesel exhaust	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234a	3.3.1-070	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-400c	3.3.1-127	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A, 1
Piping, piping components (spectacle flange)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	A
Pump casing (jockey)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A

Table 3.3.2-13 Auxiliary Systems - Fire Service - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (motor- and engine-driven column)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A
Pump casing (motor- and engine-driven)	PB	Gray cast iron	(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A
					Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A
Sprinkler head	DF;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	A

Table 3.3.2-13 Auxiliary Systems - Fire Service - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	A, 1
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Raw water	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-473b	3.3.1-160	E, 3
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-47	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	A, 1
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A, 1

Table 3.3.2-13 Auxiliary Systems - Fire Service - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer element	FLT	Copper alloy (>15% Zn)	(E) Raw water	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-473b	3.3.1-160	E, 3
				Loss of material	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	A
					Selective Leaching (B2.1.21)	VII.G.A-47	3.3.1-072	A
		Nickel alloy	(E) Raw water	Loss of material	Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	A
		Stainless steel	(E) Raw water	Loss of material	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	A
Strainer element (fire pump suction)	FLT	Copper alloy	(E) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	A
Tank (diesel fire pump fuel oil)	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234a	3.3.1-070	A
Tank (low pressure carbon dioxide)	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (retarding chamber)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	A, 1

Table 3.3.2-13 Auxiliary Systems - Fire Service - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
			(I) Raw water	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-473b	3.3.1-160	E, 3
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-47	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	A, 1
		Ductile iron	(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A
			(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-198	3.3.1-109	A
		Ductile iron with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-414	3.3.1-139	A
						VII.G.A-415	3.3.1-140	A
			(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-198	3.3.1-109	A

Table 3.3.2-13 Auxiliary Systems - Fire Service - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234a	3.3.1-070	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.G.AP-127	3.3.1-097	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	A, 1

Table 3.3.2-13 Plant-Specific Notes:

1. Flow blockage is not applicable to piping components with a leakage boundary function (i.e., those that do not support a function of delivering downstream flow).

2. Cracking of copper alloy (>15% Zn) in air and condensation environments requires the presence of ammonia-based compounds. In indoor air, such compounds could be conveyed to external surfaces of components via leakage through the insulation from bolted connections. However, internal surfaces of components are not exposed to contamination from external leakage sources. Therefore, internal cracking of these components is not expected.

3. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program has been substituted for the Open-Cycle Cooling Water System (B2.1.11) program to manage cracking of copper alloy (>15% Zn) components exposed to raw water.

4. The Fire Protection (B2.1.15)) program will manage the applicable aging effects for piping associated with the carbon dioxide system.

5. The gray cast iron and gray cast iron with internal lining piping, piping components exposed to soil are pipe fittings.

Table 3.3.2-14 Auxiliary Systems - Fuel Handling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Treated borated water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Fuel transfer tube	PB;SS	Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-38	3.5.1-010	C
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-38	3.5.1-010	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Fuel transfer tube (bellows)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Fuel transfer tube (blind flange)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-38	3.5.1-010	C
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-38	3.5.1-010	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A

Table 3.3.2-14 Auxiliary Systems - Fuel Handling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fuel transfer tube (penetration sleeve)	PB;SS	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A, 2
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A, 2
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A, 2
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A, 2
		Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B2.1.30)	II.A3.C-16	3.5.1-028	C, 1
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.C-16	3.5.1-028	C, 1
			(I) Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.C-16	3.5.1-028	C, 1
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.C-16	3.5.1-028	C, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Gate seal	PB	Elastomer	(I) Air – dry	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.A-504	3.3.1-085	A
			(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
			(E) Treated borated water	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.A3.AP-100	3.3.1-085	E, 3
Piping, piping components	LB;PB;SI	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pulsation dampener (upender hydraulic)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Pump casing (upender hydraulic - cylinder)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-14 Auxiliary Systems - Fuel Handling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (upender hydraulic - manifold)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A
					Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
Reactor cavity seal ring	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(E) Treated borated water	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.A3.AP-100	3.3.1-085	E, 3
		Stainless steel	(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Tank (upender hydraulic)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Valve body	LB;PB;SI	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A
					Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A

Table 3.3.2-14 Plant-Specific Notes:

1. The ASME Section XI, Subsection IWE (B2.1.30) and 10 CFR Part 50, Appendix J (B2.1.33) programs manage aging of the internal and external surfaces of the steel fuel transfer tube penetration sleeve that is exposed to air.

2. The stainless steel portion of the fuel transfer tube penetration sleeve is within the Fuel Handling Building and does not provide a containment pressure boundary.

3. The External Surfaces Monitoring of Mechanical Components (B2.1.23) program has been substituted for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program to manage the applicable aging effects of the external surfaces of the elastomer fuel pool gate seals and the refueling cavity seal.

Table 3.3.2-15 Auxiliary Systems - Gaseous Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Compressor housing (waste gas)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
Filter housing (waste gas drain)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 1
Flow element (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 1
Heat exchanger (compressor - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (compressor - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (compressor - tube)	PB	Stainless steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(E) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A

Table 3.3.2-15 Auxiliary Systems - Gaseous Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (compressor - tubesheet)	PB	Stainless steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(E) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Heat exchanger (recombiner cooler condenser - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A, 1
Heat exchanger (recombiner cooler condenser - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (recombiner cooler condenser - tube)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A, 1
Heat exchanger (recombiner cooler condenser - tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	C
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-15 Auxiliary Systems - Gaseous Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A, 1
Pump casing (decay tank drain)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 1

Table 3.3.2-15 Auxiliary Systems - Gaseous Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Tank (compressor separator)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	C
Tank (phase separator)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 1
Trap body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A, 1

Table 3.3.2-15 Auxiliary Systems - Gaseous Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
					Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A, 1

Table 3.3.2-15 Plant-Specific Notes:

1. This waste water environment is associated with primary system gaseous waste condensation, or the product of hydrogen recombiners. It is not expected to contain contaminants, but is not monitored by the Water Chemistry (B2.1.2) program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will manage loss of material in this environment.

Table 3.3.2-16 Auxiliary Systems - Hydrogen Removal, Post Accident - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Flow indicator (hydrogen analyzer)	PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
Flow indicator body (hydrogen analyzer)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
Heat exchanger (analyzer sample cooling coil)	HT;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.A-770a	3.3.1-241	A
				Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-419	3.3.1-096a	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.A-770a	3.3.1-241	A
				Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-419	3.3.1-096a	A
Insulation (safety-related heat traced components)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
Orifice	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A

Table 3.3.2-16 Auxiliary Systems - Hydrogen Removal, Post Accident - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components (containment pressure capillary tubing)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (hydrogen analyzer sample)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
Recombiner (base)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Recombiner (heat duct)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A

Table 3.3.2-16 Auxiliary Systems - Hydrogen Removal, Post Accident - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Recombiner (housing)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
Separator (hydrogen analyzer)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
Valve body	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-16 Plant-Specific Notes: None

Table 3.3.2-17 Auxiliary Systems - Incore Instrumentation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A

Table 3.3.2-17 Plant-Specific Notes: None

Table 3.3.2-18 Auxiliary Systems - Industrial Cooler - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Condensation	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Flow Element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Heat exchanger (industrial cooling - plate)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Level glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Closed-cycle cooling water	None	None	VII.J.AP-166	3.3.1-117	A
Level glass (body)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-18 Auxiliary Systems - Industrial Cooler - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A; 1
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-270	3.3.1-088	A
Pump casing (industrial cooling)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Tank (chemical feed)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-75	3.4.1-012	E, 2

Table 3.3.2-18 Auxiliary Systems - Industrial Cooler - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (expansion reservoir)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
Tank (industrial cooling expansion)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-270	3.3.1-088	A

Table 3.3.2-18 Plant-Specific Notes:

1. Closed-cycle cooling water is a subset of treated water per NUREG-2191, Section IX.D, and therefore this GALL line item is applicable for erosion.
2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program has been substituted for the Water Chemistry (B2.1.2) and the One-Time Inspection (B2.1.20) programs to manage the applicable aging effects for chemical feed tank.

Table 3.3.2-19 Auxiliary Systems - Instrument Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Accumulator (PORV backup air)	PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Filter silencer body	SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Flexible hose	PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
Heat exchanger (reactor building instrument air compressor jacket)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (reactor building instrument air dryer compressor - jacket)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A

Table 3.3.2-19 Auxiliary Systems - Instrument Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (reactor building instrument air dryer condenser - channel)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	C
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	C
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-19 Auxiliary Systems - Instrument Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (portable bottle for local valve operation)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Trap body	LB	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.A-763a	3.3.1-234	A
			(I) Waste water	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-451c	3.3.1-189	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-776c	3.3.1-247	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB;PB;SI	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-19 Plant-Specific Notes: None

Table 3.3.2-20 Auxiliary Systems - Leak Detection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Flow element (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Flow indicator	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Treated borated water	None	None	VII.J.AP-52	3.3.1-117	A
Flow indicator (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-20 Plant-Specific Notes: None

Table 3.3.2-21 Auxiliary Systems - Liquid Effluents From Nuclear Plant to Penstock - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-21 Plant-Specific Notes: None

Table 3.3.2-22 Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Demineralizer shell	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Eductor	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-22 Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (concentrates sample cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	C
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (concentrates sample cooler - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (concentrates sample cooler - tube and tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	C
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (evaporator - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	C
Heat exchanger (evaporator - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	C
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A

Table 3.3.2-22 Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (evaporator condenser - channel)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (evaporator condenser - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	C
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (evaporator condenser - tube and tubesheet)	PB	Stainless steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(E) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	C
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (evaporator distillate cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	C
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (evaporator distillate cooler - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C

Table 3.3.2-22 Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (evaporator distillate cooler - tube and tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	C
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (evaporator feed preheater - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	C
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (evaporator feed preheater - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	C
Heat exchanger (evaporator vent condenser - channel)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (evaporator vent condenser - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	C
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A

Table 3.3.2-22 Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (evaporator vent condenser - tube and tubesheet)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (reactor coolant drain tank - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (reactor coolant drain tank - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (reactor coolant drain tank - tube)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (reactor coolant drain tank - tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-22 Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.E1.A-407	3.3.1-126	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Pump casing (chemical drain tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (evaporator concentrates)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-22 Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (evaporator condensate)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (evaporator distillate)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (evaporator feed)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (floor drain tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (laundry and hot shower tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (reactor coolant drain tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Pump casing (spent resin sluice)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-22 Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (waste monitor tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Rupture disc	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Waste water	None	None	VII.J.AP-277	3.3.1-119	A
Sight glass (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (chemical drain)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (evaporator condensate)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-22 Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (floor drain)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (laundry and hot shower)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (reactor coolant drain)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Tank (reagent tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (spent resin storage)	LB	Stainless steel	(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Tank (waste holdup)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (waste monitor)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Trap body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-22 Auxiliary Systems - Liquid Waste Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A

Table 3.3.2-22 Plant-Specific Notes: None

Table 3.3.2-23 Auxiliary Systems - Material Handling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Stainless steel	(E) Air – indoor uncontrolled	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B5.T-37b	3.5.1-100	A
				Loss of preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)	III.B5.TP-261	3.5.1-088	E, 1
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.A-99	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.A-99	3.3.1-125	C
				Loss of preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)	III.B5.TP-261	3.5.1-088	E, 1
		Steel	(E) Air – indoor uncontrolled	Loss of preload; loss of material; cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)	VII.B.A-730	3.3.1-199	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Crane rails and retaining clips, girders, beams, plates	SS	Stainless steel	(E) Air – indoor uncontrolled	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B5.T-37b	3.5.1-100	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.A-99	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.A-99	3.3.1-125	C
		Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	VII.B.A-06	3.3.1-001	A, 2
				Loss of material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)	VII.B.A-07	3.3.1-052	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-23 Plant-Specific Notes:

1. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13) program has been substituted for the Structures Monitoring (B2.1.35) program to manage loss of preload for these bolting components.

2. Crane load cycle limit is a TLAA for each of the in-scope cranes identified in Section 2.3.3.23.

Table 3.3.2-24 Auxiliary Systems - Nitrogen Blanketing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Valve body	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A

Table 3.3.2-24 Plant-Specific Notes: None

Table 3.3.2-25 Auxiliary Systems - Nuclear and Miscellaneous Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Stainless steel	(E) Waste water	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Waste water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Level glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Waste water	None	None	VII.J.AP-277	3.3.1-119	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-25 Auxiliary Systems - Nuclear and Miscellaneous Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Concrete	None	None	VII.J.AP-282	3.3.1-112	A, 2
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A, 1

Table 3.3.2-25 Auxiliary Systems - Nuclear and Miscellaneous Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (sump)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (waste drain tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (valve stem leakoff drain pot)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-25 Auxiliary Systems - Nuclear and Miscellaneous Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (waste drain)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A, 1

Table 3.3.2-25 Plant-Specific Notes:

1. Flow blockage is not applicable to piping components with a leakage boundary function (i.e., those that do not support a function of delivering downstream flow).

2. Piping is embedded within interior concrete that is not potentially exposed to groundwater.

Table 3.3.2-26 Auxiliary Systems - Nuclear Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Condensation	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Delay coil	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Flexible hose	LB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Treated water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1

Table 3.3.2-26 Auxiliary Systems - Nuclear Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Heat exchanger (auxiliary sample cooler - shell)	LB	Stainless steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
		Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Heat exchanger (sample cooler - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A

Table 3.3.2-26 Auxiliary Systems - Nuclear Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (sample cooler - tube)	PB	Nickel alloy	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-471	3.3.1-147	C, 2
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	IV.C2.RP-40	3.1.1-082	C, 2
					Water Chemistry (B2.1.2)	IV.C2.RP-40	3.1.1-082	C, 2
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C, 2
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C, 2
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.C.E-457	3.2.1-114	C, 2
					Water Chemistry (B2.1.2)	V.C.E-457	3.2.1-114	C, 2
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.E-428	3.2.1-022	C, 2
					Water Chemistry (B2.1.2)	V.D1.E-428	3.2.1-022	C, 2
Heat exchanger (sample cooler chiller - channel)	LB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F1.A-417	3.3.1-096b	A
Heat exchanger (water bath)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C

Table 3.3.2-26 Auxiliary Systems - Nuclear Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.E.SP-88	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-26 Auxiliary Systems - Nuclear Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (flush / dilution)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
					Selective Leaching (B2.1.21)	VII.C2.AP-31	3.3.1-072	A
Pump casing (flush water)	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
Pump casing (liquid sample circulation)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Pump casing (mannitol)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Pump casing (nitric acid)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1

Table 3.3.2-26 Auxiliary Systems - Nuclear Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (sample cooler chiller)	LB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Pump casing (sodium hydroxide)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Pump casing (waste)	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Waste water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
Sample flask	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Sample sink	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-26 Auxiliary Systems - Nuclear Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (chemical)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Tank (flush / dilution)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	C
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	C
Tank (flush water)	LB	Stainless steel	(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Tank (sample cooler chiller reservoir)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-26 Auxiliary Systems - Nuclear Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.E.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Waste sump and panel enclosure	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-26 Plant-Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program has been substituted for the Water Chemistry (B2.1.2) program and the One-Time Inspection (B2.1.20) program to manage the applicable aging effects for chemical treatment components.

2. Sample coolers provide a safety-related pressure boundary for the component cooling system, but are not credited with a heat transfer function for license renewal.

Table 3.3.2-27 Auxiliary Systems - Radiation Monitoring - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flow element	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (air sample)	SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A

Table 3.3.2-27 Auxiliary Systems - Radiation Monitoring - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Radiation monitor	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-27 Plant-Specific Notes: None

Table 3.3.2-28 Auxiliary Systems - Radwaste Solidification & Solids Handling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Flexible hose	LB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Waste water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-728	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-550	3.3.1-096	A
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-28 Auxiliary Systems - Radwaste Solidification & Solids Handling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (waste evaporator concentrates transfer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Sample valve enclosure	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (waste blending)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (waste evaporator concentrates)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Trap body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-28 Plant-Specific Notes: None

Table 3.3.2-29 Auxiliary Systems - Reactor Building Cooling Unit Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-29 Plant-Specific Notes: None

Table 3.3.2-30 Auxiliary Systems - Reactor Building Leak Rate Testing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Valve body	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-30 Plant-Specific Notes: None

Table 3.3.2-31 Auxiliary Systems - Reactor Makeup Water Supply - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Flow element	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Heat exchanger (reactor makeup water pump motor - water jacket)	HT;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VIII.E.SP-96	3.4.1-018	A
					Water Chemistry (B2.1.2)	VIII.E.SP-96	3.4.1-018	A
Insulation (safety-related heat traced components)	TI	Non-metallic thermal insulation	(E) Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-31 Auxiliary Systems - Reactor Makeup Water Supply - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (reactor makeup water)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Tank (reactor makeup water storage)	PB	Stainless steel	(E) Air – outdoor	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VII.I.A-734a	3.3.1-205	A
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VII.I.A-761a	3.3.1-232	A
			(E) Concrete	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VII.E5.A-759	3.3.1-230	A
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VII.E5.A-758	3.3.1-229	A
			(I) Treated water	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VII.H1.A-413	3.3.1-137	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-31 Plant-Specific Notes: None

Table 3.3.2-32 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Accumulator	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Condensation	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Raw water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-241	3.3.1-109	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Calibration column	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Treated water	None	None	VII.J.AP-51	3.3.1-117	A
Calibration column (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Flexible hose	PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
Flow element	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-32 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (service water pump motor bearing cooling coils)	HT;PB	Copper alloy	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C1.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.C1.AP-133	3.3.1-099	A
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	VII.C1.A-791	3.3.1-257	A
					One-Time Inspection (B2.1.20)	VII.C1.A-791	3.3.1-257	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	C
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	A
Heat exchanger (service water pumphouse cooling coils)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Insulation (steel with internal lining piping)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
Nozzle (water jet air exhauster)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	A
Piping, piping components	LB;PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-32 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
		Stainless steel with internal lining	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-414	3.3.1-139	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
						VII.I.A-405a	3.3.1-132	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-400a	3.3.1-127	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.C1.A-409	3.3.1-126	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-198	3.3.1-109	A

Table 3.3.2-32 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Steel with internal lining	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.C1.A-414	3.3.1-139	A
Piping, piping components (not covered by NRC GL 89-13)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-400b	3.3.1-127	A
						VII.C1.A-727	3.3.1-134	A
Pump casing (chemical injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Pump casing (DRPI cooling unit booster)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-32 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (service water booster)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	A
Pump casing (service water)	PB	Steel	(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	A
Tank (chemical storage)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-162	3.4.1-083	E, 1
Traveling screen element	FLT	Stainless steel	(E) Raw water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Valve body	LB;PB;SI	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-32 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
		Stainless steel with internal lining	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VII.G.A-414	3.3.1-139	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VII.I.AP-198	3.3.1-109	A

Table 3.3.2-32 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body (not covered by NRC GL 89-13)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-32 Plant-Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program has been substituted for the Water Chemistry (B2.1.2) and the One-Time Inspection (B2.1.20) programs to manage the applicable aging effects for chemical treatment components.

Table 3.3.2-33 Auxiliary Systems - Spent Fuel Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Nickel alloy	(E) Treated borated water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Demineralizer shell	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Flow element	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Heat exchanger (spent fuel - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	C
Heat exchanger (spent fuel - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.A3.AP-189	3.3.1-046	A

Table 3.3.2-33 Auxiliary Systems - Spent Fuel Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (spent fuel - tube)	HT;PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.A3.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.A3.A-101	3.3.1-017	A
Heat exchanger (spent fuel - tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	C
Insulation (safety-related heat traced components)	TI	Non-metallic thermal insulation	(E) Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(E) Concrete	None	None	VII.J.AP-19	3.3.1-202	A, 1
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.E1.A-407	3.3.1-126	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-33 Auxiliary Systems - Spent Fuel Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (spent fuel cooling)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Pump casing (spent fuel purification)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-33 Plant-Specific Notes:

1. Piping is embedded within interior concrete that is not potentially exposed to groundwater.

Table 3.3.2-34 Auxiliary Systems - Station Service Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Valve body	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-34 Plant-Specific Notes: None

Table 3.3.2-35 Auxiliary Systems - Thermal Regeneration - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Condensation	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Condensation	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Demineralizer shell	PB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Flow element	LB;PB;RF	Stainless steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Heat exchanger (chiller condenser and evaporator - channel)	LB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C

Table 3.3.2-35 Auxiliary Systems - Thermal Regeneration - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (chiller lubricating oil - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-131	3.3.1-098	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-131	3.3.1-098	A
Heat exchanger (chiller lubricating oil - shell)	LB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
Heat exchanger (letdown chiller - channel)	PB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (letdown chiller - shell)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
Heat exchanger (letdown chiller - tube)	HT;PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A
Heat exchanger (letdown chiller - tubesheet)	PB	Stainless steel	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C

Table 3.3.2-35 Auxiliary Systems - Thermal Regeneration - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (letdown reheat - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
Heat exchanger (letdown reheat - shell)	PB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (letdown reheat - tube)	PB	Stainless steel	(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
Heat exchanger (letdown reheat - tubesheet)	PB	Stainless steel	(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (moderating - channel)	PB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (moderating - shell)	PB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-770a	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (moderating - tube)	HT;PB	Stainless steel	(I) Treated borated water	Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A
Heat exchanger (moderating - tubesheet)	PB	Stainless steel	(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C

Table 3.3.2-35 Auxiliary Systems - Thermal Regeneration - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
Pump casing (chiller circulating)	LB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
Pump casing (chiller oil)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A

Table 3.3.2-35 Auxiliary Systems - Thermal Regeneration - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
Tank (chiller surge)	LB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A

Table 3.3.2-35 Auxiliary Systems - Thermal Regeneration - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-133	3.3.1-099	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A

Table 3.3.2-35 Plant-Specific Notes: None

Tables 3.3.2-1 through 3.3.2-45 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

F. Material not in NUREG-2191 for this component.

G. Environment not in NUREG-2191 for this component and material.

H. Aging effect not in NUREG-2191 for this component, material and environment combination.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

3.4 AGING MANAGEMENT OF STEAM AND POWER CONVERSION SYSTEMS

3.4.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.4, Steam and Power Conversion Systems, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Auxiliary Boiler Steam & Feedwater (Section 2.3.4.1)
- Condensate (Section 2.3.4.2)
- Emergency Feedwater (Section 2.3.4.3)
- Extraction Steam (Section 2.3.4.4)
- Feedwater (Section 2.3.4.5)
- Gland Sealing Steam (Section 2.3.4.6)
- Main Steam (Section 2.3.4.7)
- Main Steam Dump (Section 2.3.4.8)
- Nuclear Blowdown Processing (Section 2.3.4.9)
- Steam Generator Blowdown (Section 2.3.4.10)
- Turbine Cycle Chemical Feed (Section 2.3.4.11)
- Turbine Cycle Sampling (Section 2.3.4.12)
- Turbine Electro-Hydraulic (Section 2.3.4.13)

3.4.2 RESULTS

The following tables summarize the results of the aging management review for Steam and Power Conversion Systems.

- Table 3.4.2-1, Steam and Power Conversion System - Auxiliary Boiler Steam & Feedwater - Aging Management Evaluation
- Table 3.4.2-2, Steam and Power Conversion System - Condensate - Aging Management Evaluation
- Table 3.4.2-3, Steam and Power Conversion System - Emergency Feedwater - Aging Management Evaluation
- Table 3.4.2-4, Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation
- Table 3.4.2-5, Steam and Power Conversion System - Feedwater - Aging Management Evaluation
- Table 3.4.2-6, Steam and Power Conversion System - Gland Sealing Steam - Aging Management Evaluation
- Table 3.4.2-7, Steam and Power Conversion System - Main Steam - Aging Management Evaluation
- Table 3.4.2-8, Steam and Power Conversion System - Main Steam Dump - Aging Management Evaluation
- Table 3.4.2-9, Steam and Power Conversion System - Nuclear Blowdown Processing - Aging Management Evaluation
- Table 3.4.2-10, Steam and Power Conversion System - Steam Generator Blowdown - Aging Management Evaluation
- Table 3.4.2-11, Steam and Power Conversion System - Turbine Cycle Chemical Feed - Aging Management Evaluation
- Table 3.4.2-12, Steam and Power Conversion System - Turbine Cycle Sampling - Aging Management Evaluation

3.4.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.4.2.1.1 Auxiliary Boiler Steam & Feedwater

Materials

The materials of construction for the auxiliary boiler steam & feedwater system component types are:

- Glass
- Gray cast iron
- Steel

Environment

The auxiliary boiler steam & feedwater system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the auxiliary boiler steam & feedwater system, require management:

- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the auxiliary boiler steam & feedwater system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.2 Condensate

Materials

The materials of construction for the condensate system component types are:

- Steel with internal coating

Environment

The condensate system component types are exposed to the following environments:

- Air – outdoor
- Soil
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the condensate system, require management:

- Loss of coating or lining integrity
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the condensate system component types:

- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)

3.4.2.1.3 Emergency Feedwater

Materials

The materials of construction for the emergency feedwater system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn)
- Non-metallic thermal insulation
- Stainless steel
- Steel
- Steel with internal coating

Environment

The emergency feedwater system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Lubricating oil
- Raw water
- Soil
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the emergency feedwater system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the emergency feedwater system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.28)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.4 Extraction Steam

Materials

The materials of construction for the extraction steam system component types are:

- Steel

Environment

The extraction steam system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Steam

Aging Effects Requiring Management

The following aging effects, associated with the extraction steam system, require management:

- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the extraction steam system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.5 Feedwater

Materials

The materials of construction for the feedwater system component types are:

- Aluminum
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The feedwater system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the feedwater system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the feedwater system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.6 Gland Sealing Steam

Materials

The materials of construction for the gland sealing steam system component types are:

- Steel

Environment

The gland sealing steam system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Steam

Aging Effects Requiring Management

The following aging effects, associated with the gland sealing steam system, require management:

- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the gland sealing steam system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.7 Main Steam

Materials

The materials of construction for the main steam system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn)
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The main steam system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Steam
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the main steam system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the main steam system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.8 Main Steam Dump

Materials

The materials of construction for the main steam dump system component types are:

- Stainless steel
- Steel

Environment

The main steam dump system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the main steam dump system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the main steam dump system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.9 Nuclear Blowdown Processing

Materials

The materials of construction for the nuclear blowdown processing system component types are:

- Stainless steel
- Steel
- Steel with internal coating

Environment

The nuclear blowdown processing system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the nuclear blowdown processing system, require management:

- Cracking
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the nuclear blowdown processing system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.10 Steam Generator Blowdown

Materials

The materials of construction for the steam generator blowdown system component types are:

- Copper alloy (>15% Zn)
- Ductile iron
- Elastomer
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The steam generator blowdown system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the steam generator blowdown system, require management:

- Cracking
- Cumulative fatigue damage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the steam generator blowdown system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.11 Turbine Cycle Chemical Feed

Materials

The materials of construction for the turbine cycle chemical feed system component types are:

- Glass
- Stainless steel
- Steel

Environment

The turbine cycle chemical feed system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the turbine cycle chemical feed system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the turbine cycle chemical feed system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.12 Turbine Cycle Sampling

Materials

The materials of construction for the turbine cycle sampling system component types are:

- Stainless steel
- Steel

Environment

The turbine cycle sampling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the turbine cycle sampling system, require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the turbine cycle sampling system component types:

- Bolting Integrity (B2.1.9)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.2 Further Evaluation of Aging Management as Recommended by NUREG-2192

NUREG-2192 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the License Renewal Application. For the steam and power conversion system, those evaluations are addressed in the following sections.

3.4.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in SRP SLR Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses." For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

[3.4.1-001] - Fatigue of Steam and Power Conversion Systems components is a time-limited aging analysis (TLAA), as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed in Section 4.3, Metal Fatigue.

3.4.2.2.2 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to stress corrosion cracking (SCC) could occur in indoor or outdoor stainless steel (SS) piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant specific operating experience (OE) and the condition of SS components are evaluated to determine if prolonged exposure to the plant specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if: (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, “One Time Inspection,” describes an acceptable program to demonstrate that SCC is not occurring. If SCC is occurring, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) GALL-SLR Report AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” for tanks; (b) GALL-SLR Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks,” for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” for internal surfaces of components that are not included in other AMPs. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one time inspections would be conducted between the 50th and 60th year of operation, as recommended by the “detection of aging effects” program element in AMP XI.M32.

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. The GALL SLR Report AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” describes an acceptable program to manage the integrity of a barrier coating.

A review of plant-specific operating experience did not identify instances of cracking of stainless steel in air. The absence of the aging effect in air environments will be confirmed by the One-Time Inspection (B2.1.20) program.

[3.4.1-002] – Cracking of stainless steel components exposed to air – indoor uncontrolled and air – outdoor is managed by the One-Time Inspection (B2.1.20) program.

3.4.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain, and changing weather conditions can result in moisture intrusion into the insulation.

Plant specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if: (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in GALL-SLR Report AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

A review of plant-specific operating experience did not identify loss of material due to pitting or crevice corrosion for stainless steel or nickel alloy piping, piping components, or tanks in air environments (air-indoor uncontrolled, air-outdoor, or condensation). The absence of the aging effect in air environments will be confirmed by the One-Time Inspection (B2.1.20) program.

[3.4.1-003] – Loss of material of stainless steel and nickel alloy components exposed to air – indoor uncontrolled and air – outdoor is managed by the One-Time Inspection (B2.1.20) program.

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.4.2.2.5 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B.

3.4.2.2.6 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant-specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant specific OE reveals repetitive occurrences. The criteria for recurrence is (a) a 10-year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5-year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant specific AMP may be proposed. Potential augmented requirements include: (i) alternative examination methods (e.g., volumetric versus external visual); (ii) augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and (iii) additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10-year search of plant specific OE, two instances of a 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

Not applicable. A review of plant-specific operating experience did not identify loss of material due to recurring internal corrosion as an applicable aging effect requiring management for metallic piping, piping components or tanks exposed to raw water or waste water in the Steam and Power Conversion Systems.

3.4.2.2.7 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation is being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

Susceptible Material: If the material is not susceptible to SCC, then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines whether the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

Aggressive Environment: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. GALL SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. If a barrier coating is credited for isolating an aluminum alloy from a potentially aggressive environment, then the barrier coating is evaluated to verify that it is impervious to the plant-specific environment. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Cracking due to stress corrosion cracking is an aging effect requiring management for aluminum alloy components exposed to air or condensation in the Steam and Power Conversion Systems. A review of plant-specific operating experience did not identify a history of cracking of aluminum alloy components. Contaminants similar to those that support degradation of aluminum also support degradation of stainless steel. Review of operating experience as discussed in topics 3.4.2.2.2 and 3.4.2.2.3 did not identify degradation of stainless steel components in air environments. The absence of the aging effect will be confirmed by the One-Time Inspection (B2.1.20) program.

[3.4.1-109] – This item evaluates cracking of aluminum components exposed to air – indoor uncontrolled. The following component types in the identified systems are exposed to air – indoor uncontrolled and are constructed of aluminum alloys that are assumed to be susceptible to SCC because the specific series of the aluminum alloy is unknown.

Feedwater system valve bodies in the instrument air supply to the feedwater isolation valves to the steam generators. These valves are exposed to a halide free air - indoor uncontrolled environment in the Auxiliary and Intermediate Buildings, are not encapsulated in materials containing halides, and are not exposed to known sources of moisture or halides.

Emergency feedwater system lube oil filter housing for the emergency feed pump turbine. This filter is exposed to a halide free air - indoor uncontrolled environment in the Intermediate Building, is not encapsulated in materials containing halides, and is not exposed to known sources of moisture or halides.

Main steam system valve body in the instrument air supply to the steam supply flow control valve to the emergency feed pump turbine. This valve is exposed to a halide free air - indoor uncontrolled environment in the Intermediate Building, is not encapsulated in materials containing halides, and is not exposed to known sources of moisture or halides.

3.4.2.2.8 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to- cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

Not applicable. There are no in-scope steel or stainless steel piping, piping components exposed to concrete in the Steam and Power Conversion Systems.

3.4.2.2.9 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should generally be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should generally be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if: (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

A review of plant-specific operating experience did not identify a history loss of material of aluminum alloy components. Contaminants similar to those that support degradation of aluminum also support degradation of stainless steel. Review of operating experience as discussed in topics 3.4.2.2.2 and 3.4.2.2.3 did not identify degradation of stainless steel components in air environments. The absence of the aging effect will be confirmed by the One-Time Inspection (B2.1.20) program.

[3.4.1-035] – Loss of material of aluminum piping, piping components exposed to air – indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program.

Results Tables: Steam and Power Conversion Systems

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-001	Steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.4.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel components exposed to steam or treated water is a TLAA. See further evaluation in Section 3.4.2.2.1.
3.4.1-002	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.2)	Consistent with NUREG-2191. Cracking of stainless steel components exposed to air – indoor uncontrolled and air – outdoor is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.4.2.2.2.
3.4.1-003	Stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.3)	Consistent with NUREG-2191. Loss of material of stainless steel components exposed to air – indoor uncontrolled and air – outdoor is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.4.2.2.3.
3.4.1-004	Steel external surfaces exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, Boric Acid Corrosion	No	Consistent with NUREG-2191.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-005	Steel piping, piping components exposed to steam, treated water	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Consistent with NUREG-2191. In addition to Steam and Power Conversion Systems, components in Auxiliary Systems (chemical and volume control) are aligned to this item.
3.4.1-006	Metallic closure bolting exposed to any environment, soil, underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.4.1-007	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, Bolting Integrity	No	Not applicable. There is no in-scope high-strength steel closure bolting exposed to air, soil, or underground in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-009	Steel, stainless steel, nickel alloy closure bolting exposed to air-indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.4.1-011	Stainless steel piping, piping components, tanks, heat exchanger components exposed to steam, treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. In addition to Steam and Power Conversion Systems, components in Auxiliary Systems (boron recycle and nuclear sampling) are aligned to this item.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-012	Steel tanks exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191, with a different aging management program credited for some components. In addition to Steam and Power Conversion Systems, components in Auxiliary Systems (industrial cooler) are aligned to this item. For Auxiliary Systems (industrial cooler), a different aging management program is credited. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program manages loss of material of steel components exposed to treated water that is not managed by the Water Chemistry (B2.1.2) program and One-Time Inspection (B2.1.20) program.
3.4.1-014	Steel piping, piping components exposed to steam, treated water	Loss of material due to general, pitting, crevice corrosion, MIC (treated water only)	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191, with a different aging management program credited for some components. In addition to Steam and Power Conversion Systems, components in Auxiliary Systems (component cooling, chilled water, liquid waste processing, fuel handling, chemical and volume control, nuclear sampling, and gaseous waste processing) are aligned to this item. For Auxiliary Systems (chilled water), a different aging management program is credited. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) manages loss of material of steel components exposed to treated water that is not managed by the Water Chemistry (B2.1.2) program and the One-Time Inspection (B2.1.20) program.
3.4.1-015	Steel heat exchanger components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. In addition to Steam and Power Conversion Systems, components in Auxiliary Systems (boron recycle and gaseous waste processing) are aligned to this item.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-016	Copper alloy, aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC (copper alloy only)	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. In addition to Steam and Power Conversion Systems, components in Auxiliary Systems (demineralized water- nuclear services, fuel handling, nuclear sampling, gaseous waste processing, air handling, and local ventilation and cooling) are aligned to this item.
3.4.1-018	Copper alloy, stainless steel heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. In addition to Steam and Power Conversion Systems, components in Auxiliary Systems (reactor makeup water supply) are aligned to this item.
3.4.1-019	Stainless steel, steel heat exchanger components exposed to raw water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope stainless steel or steel heat exchanger components exposed to raw water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-020	Copper alloy, stainless steel piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope copper alloy or stainless steel piping, piping components exposed to raw water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-022	Stainless steel, copper alloy, steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope stainless steel, copper alloy, or steel heat exchanger tubes exposed to raw water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-023	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F) in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-025	Steel heat exchanger components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope steel heat exchanger components exposed to closed-cycle cooling water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-026	Stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope stainless steel heat exchanger components or piping, piping components exposed to closed-cycle cooling water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-027	Copper alloy piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope copper alloy piping, piping components exposed to closed-cycle cooling water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-028	Steel, stainless steel, copper alloy heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope steel, stainless steel, or copper alloy heat exchanger tubes exposed to closed-cycle cooling water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-030	Steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete, air, condensation	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191.
3.4.1-032	Gray cast iron, ductile iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Not applicable. There are no in-scope gray cast iron, ductile iron piping, piping components exposed to soil in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-033	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components exposed to treated water, raw water, closed-cycle cooling water	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Consistent with NUREG-2191. In addition to Steam and Power Conversion Systems, components in Auxiliary Systems (demineralized water- nuclear services) are aligned to this item.
3.4.1-034	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.
3.4.1-035	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.9)	Consistent with NUREG-2191. Loss of material of aluminum piping, piping components exposed to air – indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.4.2.2.9.
3.4.1-036	Steel piping, piping components exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. Loss of material of steel piping, piping components exposed to air – outdoor is addressed in row 3.4.1-034. The associated NUREG-2191 aging items are not used.
3.4.1-037	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope steel piping, piping components exposed to condensation in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-038	Steel piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. There are no in-scope steel piping, piping components exposed to raw water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-040	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.4.1-041	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope steel heat exchanger components exposed to lubricating oil in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-042	Aluminum piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.4.1-043	Copper alloy piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.4.1-044	Stainless steel piping, piping components, heat exchanger components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.4.1-045	Aluminum heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope aluminum heat exchanger tubes exposed to lubricating oil in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-046	Stainless steel, steel, copper alloy heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-047	Stainless steel piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope stainless steel piping, piping components, tanks, or closure bolting exposed to soil or concrete in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-048	Nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope nickel alloy piping, piping components, tanks, or closure bolting exposed to soil or concrete in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-050	Steel piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Consistent with NUREG-2191.
3.4.1-051	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Not applicable. There are no in-scope steel piping, piping components exposed to concrete in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-052	Aluminum piping, piping components exposed to gas	None	None	No	Not applicable. There are no in-scope aluminum piping, piping components exposed to gas in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-053	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. Boric acid corrosion is not an applicable aging effect for copper alloy or copper alloy (>8% Al) piping, piping components, so air with borated water leakage environment is not assigned to these materials. The associated NUREG-2191 aging items are not used.
3.4.1-054	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-055	Glass piping elements exposed to lubricating oil, air, condensation, raw water, treated water, air with borated water leakage, gas, closed-cycle cooling water	None	None	No	Consistent with NUREG-2191.
3.4.1-056	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. Boric acid corrosion is not an applicable aging effect for nickel alloy piping, piping components, so air with borated water leakage environment is not assigned to this material. The associated NUREG-2191 aging items are not used.
3.4.1-057	PVC piping, piping components exposed to air – indoor uncontrolled, condensation	None	None	No	Not applicable. There are no in-scope PVC piping, piping components exposed to air – indoor uncontrolled or condensation in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-058	Stainless steel piping, piping components exposed to gas	None	None	No	Not applicable. There are no in-scope stainless steel piping, piping components exposed to gas in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-059	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Not applicable. There are no in-scope steel piping, piping components exposed to air – indoor controlled, gas in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-060	Metallic piping, piping components exposed to steam, treated water	Wall thinning due to erosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Consistent with NUREG-2191. In addition to Steam and Power Conversion Systems, components in Auxiliary Systems (chemical and volume control, chilled water, component cooling, industrial cooler) are aligned to this item.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-061	Metallic piping, piping components, tanks exposed to raw water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, Open-Cycle Cooling Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Yes (SRP-SLR Section 3.4.2.2.6)	Not applicable. A review of plant-specific operating experience did not identify recurring internal corrosion in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-062	Steel, stainless steel or aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to treated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Not applicable. There are no in-scope steel, stainless steel, or aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-063	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, External Surfaces Monitoring of Mechanical Components or AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191. Loss of material of the condensate storage tank exposed to air – outdoor is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.
3.4.1-064	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-066	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, lubricating oil	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191.
3.4.1-067	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191.
3.4.1-068	Gray cast iron, ductile iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Not applicable. There are no in-scope gray cast iron, ductile iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, or waste water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-070	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to lubricating oil, treated water, treated borated water, raw water, waste water	Loss of material due to general (steel; copper alloy in raw water, waste water only), pitting, crevice corrosion, MIC (raw water, waste water environments only)	AMP XI.M18, Bolting Integrity	No	Not applicable. There are no in-scope stainless steel, steel, nickel alloy, or copper alloy closure bolting exposed to lubricating oil, treated water, treated borated water, raw water, or waste water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-072	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope stainless steel, or aluminum piping, piping components, or tanks exposed to soil or concrete in the Steam and Power Conversion Systems. VCSNS soil does not correspond to a carbonate/bicarbonate environment. The associated NUREG-2191 aging items are not used.
3.4.1-073	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, Bolting Integrity	No	Consistent with NUREG-2191.
3.4.1-074	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.2)	Not applicable. There are no in-scope stainless steel underground piping, piping components, tanks in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-075	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There are no in-scope stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes exposed to air or condensation in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-077	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-078	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope elastomer piping, piping components, seals with internal surfaces exposed to air or condensation in the Steam and Power Conversion Systems. Hardening or loss of strength of elastomer piping, piping components or seals exposed to an external environment of air - indoor uncontrolled is addressed in row 3.4.1-077. The associated NUREG-2191 aging items are not used.
3.4.1-081	Steel components exposed to treated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.
3.4.1-082	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Not applicable. There are no in-scope stainless steel piping, piping components exposed to concrete in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-083	Stainless steel, nickel alloy tanks exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191, with a different aging management program credited for some components. In addition to Steam and Power Conversion System, components in Auxiliary Systems (component cooling, chilled water, and service water) are aligned to this item. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program manages loss of material of stainless steel components exposed to treated water that is not managed by the Water Chemistry (B2.1.2) program and One-Time Inspection (B2.1.20) program.
3.4.1-084	Stainless steel, nickel alloy piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-085	Stainless steel, nickel alloy piping, piping components, PWR heat exchanger components exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191, with a different aging management program credited for some components. In addition to Steam and Power Conversion System, components in Auxiliary Systems (boron recycle, chemical and volume control, component cooling, chilled water, demineralized water-nuclear services, fuel handling, gaseous waste processing, hydrogen removal-post accident, nuclear and miscellaneous drains, nuclear sampling, radiation monitoring, reactor makeup water supply, spent fuel cooling, and service water) are aligned to this item. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program manages loss of material of stainless steel components exposed to treated water that is not managed by the Water Chemistry (B2.1.2) program and One-Time Inspection (B2.1.20) program.
3.4.1-086	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes internal to components exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes internal to components exposed to air or condensation in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-089	Steel, stainless steel, copper alloy piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope steel, stainless steel, or copper alloy piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-090	Steel, stainless steel, copper alloy heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Reduction of heat transfer due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope steel, stainless steel, or copper alloy heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13) in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-091	Steel, stainless steel, copper alloy heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope steel, stainless steel, or copper alloy heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13) in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-092	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Not applicable. There are no in-scope copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-094	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no in-scope aluminum underground piping, piping components, tanks in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-095	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.3)	Not applicable. There are no in-scope stainless steel or nickel alloy underground piping, piping components or tanks in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-096	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Not applicable. There are no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-097	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-098	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.3)	Not applicable. There are no in-scope stainless steel or nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-099	Stainless steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Not applicable. There are no in-scope stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil or concrete in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-100	Stainless steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.2)	Not applicable. There are no in-scope stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air or condensation in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-101	Stainless steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Not applicable. There are no in-scope stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil or concrete in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-102	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no in-scope aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air, condensation, soil, concrete, raw water, or waste water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-103	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.3)	Not applicable. Loss of material of stainless steel or nickel alloy piping, piping components and tanks exposed to air – indoor uncontrolled or air – outdoor is addressed in row 3.4.1-003. The associated NUREG-2191 aging items are not used.
3.4.1-104	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.2)	Not applicable. Cracking of stainless steel piping, piping components and tanks exposed to air – indoor uncontrolled or air – outdoor is addressed in row 3.4.1-002. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-105	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. Cracking of aluminum piping, piping components, tanks exposed to air – indoor uncontrolled is addressed in row 3.4.1-109. The associated NUREG-2191 aging items are not used.
3.4.1-106	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to air, condensation	Cracking due to SCC	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191. In addition to Steam and Power Conversion Systems, components in Auxiliary Systems (component cooling, chilled water, and demineralized water-nuclear services) are aligned to this item.
3.4.1-107	Copper alloy (>15% Zn or >8% Al) tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. There are no in-scope copper alloy (>15% Zn or >8% Al) tanks exposed to air or condensation in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-109	Aluminum piping, piping components, tanks exposed to air, condensation, raw water, waste water	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.7)	Consistent with NUREG-2191. Cracking of aluminum components exposed to air – indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.4.2.2.7.
3.4.1-112	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no in-scope aluminum underground piping, piping components or tanks in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-114	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. There are no in-scope titanium heat exchanger tubes exposed to treated water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-115	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not applicable. There are no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes or piping, piping components exposed to treated water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-116	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. There are no in-scope titanium heat exchanger tubes exposed to closed-cycle cooling water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-117	Aluminum piping, piping components, tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope aluminum piping, piping components or tanks exposed to soil or concrete in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-119	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. Loss of material of aluminum piping, piping components, exposed to air is addressed in row 3.4.1-035. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-120	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Consistent with NUREG-2191.
3.4.1-123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no elastomer piping, piping component or seals with an internal air environment. Loss of material of elastomer piping, piping components exposed to air (externally) is addressed in row 3.4.1-122. The associated NUREG-2191 aging items are not used.
3.4.1-124	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. There are no in-scope PVC piping, piping components or tanks exposed to concrete in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-125	PVC piping, piping components, tanks exposed to soil	Loss of material due to wear	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope PVC piping, piping components or tanks exposed to soil in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-126	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not applicable. There are no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes or piping, piping components exposed to closed-cycle cooling water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-127	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. Boric acid corrosion is not an applicable aging effect for aluminum, so air with borated water leakage environment is not assigned to these materials. The associated NUREG-2191 aging items are not used.
3.4.1-128	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. There are no in-scope copper alloy piping, piping components exposed to concrete in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-129	Copper alloy piping, piping components exposed to soil, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. There are no in-scope copper alloy piping, piping components exposed to soil or underground in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-130	Titanium piping, piping components, heat exchanger components other than tubes exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope titanium piping, piping components or heat exchanger components other than tubes exposed to raw water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-131	Copper alloy (>15% Zn) piping, piping components exposed to air with borated water leakage	Loss of material due to boric acid corrosion	AMP XI.M10, Boric Acid Corrosion	No	Consistent with NUREG-2191.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-132	Stainless steel piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. Boric acid corrosion is not an applicable aging effect for stainless steel, so air with borated water leakage environment is not assigned to these materials. The associated NUREG-2191 aging items are not used.
3.4.1-133	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope aluminum piping, piping components exposed to raw water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-134	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.
3.4.1-135	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope polymeric piping, piping components, ducting, ducting components, or seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, or soil in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.

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Results Tables: Steam and Power Conversion Systems AMR Results

Table 3.4.2-1 Steam and Power Conversion System - Auxiliary Boiler Steam & Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Bolting	LB;PB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Heat exchanger (condensate return - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
Heat exchanger (condensate return - shell)	LB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Heat exchanger (condensate return - shell)	LB	Steel	(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	C
Heat exchanger (condensate return - shell)	LB	Steel	(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	C
Heat exchanger (condensate return - shell)	LB	Steel	(I) Steam	Loss of material	Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	C
Piping, piping components	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
Piping, piping components	LB;PB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Piping, piping components	LB;PB	Steel	(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
Piping, piping components	LB;PB	Steel	(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
Piping, piping components	LB;PB	Steel	(I) Steam	Loss of material	Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Piping, piping components	LB;PB	Steel	(I) Steam	Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
Piping, piping components	LB;PB	Steel	(I) Steam	Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-408	3.4.1-060	A
Piping, piping components	LB;PB	Steel	(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
Piping, piping components	LB;PB	Steel	(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
Piping, piping components	LB;PB	Steel	(I) Treated water	Loss of material	Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
Piping, piping components	LB;PB	Steel	(I) Treated water	Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	A
Piping, piping components	LB;PB	Steel	(I) Treated water	Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.G.S-408	3.4.1-060	A

Table 3.4.2-1 Steam and Power Conversion System - Auxiliary Boiler Steam & Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (condensate return)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Treated water	None	None	VIII.I.SP-35	3.4.1-055	A
Sight glass (body)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
Steam trap body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A

Table 3.4.2-1 Steam and Power Conversion System - Auxiliary Boiler Steam & Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
Tank (condensate return)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-75	3.4.1-012	A
					Water Chemistry (B2.1.2)	VIII.E.SP-75	3.4.1-012	A
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	C

Table 3.4.2-1 Steam and Power Conversion System - Auxiliary Boiler Steam & Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A

Table 3.4.2-1 Plant-Specific Notes: None

Table 3.4.2-2 Steam and Power Conversion System - Condensate - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (condensate storage)	PB	Steel with internal coating	(E) Air – outdoor	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VIII.H.S-402b	3.4.1-063	A
			(E) Soil	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VIII.E.SP-115	3.4.1-030	A
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VIII.E.S-401	3.4.1-066	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VIII.E.S-414	3.4.1-067	A

Table 3.4.2-2 Plant-Specific Notes: None

Table 3.4.2-3 Steam and Power Conversion System - Emergency Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Accumulator	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	C
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
						VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Bolting	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VIII.H.S-421	3.4.1-073	A
				Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air – outdoor	Cracking	Bolting Integrity (B2.1.9)	VIII.H.S-421	3.4.1-073	A
				Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Filter housing	PB;SI	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.G.S-457b	3.4.1-109	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-147a	3.4.1-035	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-114	3.4.1-042	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-114	3.4.1-042	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-91	3.4.1-040	A

Table 3.4.2-3 Steam and Power Conversion System - Emergency Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flow element	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.G.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.G.SP-87	3.4.1-085	A
Heat exchanger (EF pump turbine lube oil - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.G.SP-118a	3.4.1-002	C
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-127a	3.4.1-003	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Heat exchanger (EF pump turbine lube oil - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.G.SP-118a	3.4.1-002	C
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-127a	3.4.1-003	C
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-79	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-79	3.4.1-044	A
Heat exchanger (EF pump turbine lube oil - tube sheet)	PB	Stainless steel	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-79	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-79	3.4.1-044	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Heat exchanger (EF pump turbine lube oil - tube)	HT;PB	Stainless steel	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-79	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-79	3.4.1-044	A
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-102	3.4.1-046	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-102	3.4.1-046	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VIII.E.SP-96	3.4.1-018	A
					Water Chemistry (B2.1.2)	VIII.E.SP-96	3.4.1-018	A
Insulation (safety-related heat traced components)	TI	Non-metallic thermal insulation	(E) Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-403	3.4.1-064	A

Table 3.4.2-3 Steam and Power Conversion System - Emergency Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.G.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-95	3.4.1-044	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.G.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.G.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.G.SP-74	3.4.1-014	A

Table 3.4.2-3 Steam and Power Conversion System - Emergency Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
		Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-479	3.4.1-131	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.G.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-127a	3.4.1-003	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VIII.G.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.G.SP-87	3.4.1-085	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-91	3.4.1-040	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.28)	VIII.H.SP-161	3.4.1-050	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.G.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-74	3.4.1-014	A

Table 3.4.2-3 Steam and Power Conversion System - Emergency Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Steel	(I) Treated water	Loss of material	Water Chemistry (B2.1.2)	VIII.G.SP-74	3.4.1-014	A
Pump Casing (motor driven emergency feedwater)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.G.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.G.SP-87	3.4.1-085	A
Pump Casing (turbine driven emergency feedwater)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.G.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.G.SP-87	3.4.1-085	A
Pump casing (turbine lube oil)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-91	3.4.1-040	A
Tank (turbine lube oil reservoir)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-91	3.4.1-040	C
					One-Time Inspection (B2.1.20)	VIII.G.SP-91	3.4.1-040	C
Turbine casing (emergency feedwater pump)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A

Table 3.4.2-3 Steam and Power Conversion System - Emergency Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-479	3.4.1-131	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-92	3.4.1-043	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.G.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-127a	3.4.1-003	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VIII.G.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.G.SP-87	3.4.1-085	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-91	3.4.1-040	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.G.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.G.SP-74	3.4.1-014	A

Table 3.4.2-3 Steam and Power Conversion System - Emergency Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VIII.G.S-401	3.4.1-066	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VIII.G.S-414	3.4.1-067	A

Table 3.4.2-3 Plant-Specific Notes: None

Table 3.4.2-4 Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Piping, piping components	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	A
Valve body	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-71	3.4.1-014	A

Table 3.4.2-4 Plant-Specific Notes: None

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Accumulator	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Flow element	LB;RF	Stainless steel	(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A
Insulation (containment penetration)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-403	3.4.1-064	A

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-127a	3.4.1-003	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-88	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Cumulative fatigue damage	TLAA	VIII.D1.S-11	3.4.1-001	A
				Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-16	3.4.1-005	A
						VIII.D1.S-408	3.4.1-060	A

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Aluminum	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.S-457b	3.4.1-109	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-147a	3.4.1-035	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-87	3.4.1-085	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A

Table 3.4.2-5 Plant-Specific Notes: None

Table 3.4.2-6 Steam and Power Conversion System - Gland Sealing Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Piping, piping components	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
						VIII.B1.S-408	3.4.1-060	A
Valve body	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A

Table 3.4.2-6 Plant-Specific Notes: None

Table 3.4.2-7 Steam and Power Conversion System - Main Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Accumulator	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Diffuser	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Drain trap	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
Insulation (containment penetration)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-403	3.4.1-064	A
Moisture collector	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A

Table 3.4.2-7 Steam and Power Conversion System - Main Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
						VIII.B1.S-408	3.4.1-060	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A

Table 3.4.2-7 Steam and Power Conversion System - Main Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A

Table 3.4.2-7 Steam and Power Conversion System - Main Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Aluminum	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.G.S-457b	3.4.1-109	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.G.SP-147a	3.4.1-035	A
		Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-479	3.4.1-131	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A

Table 3.4.2-7 Plant-Specific Notes: None

Table 3.4.2-8 Steam and Power Conversion System - Main Steam Dump - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Drain trap	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
Piping, piping components	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
						VIII.B1.S-408	3.4.1-060	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
Strainer body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A

Table 3.4.2-8 Steam and Power Conversion System - Main Steam Dump - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A

Table 3.4.2-8 Plant-Specific Notes: None

Table 3.4.2-9 Steam and Power Conversion System - Nuclear Blowdown Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Demineralizer shell (polishing)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Demineralizer shell (primary)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Heat exchanger (holdup tank transfer pump motor cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A

Table 3.4.2-9 Steam and Power Conversion System - Nuclear Blowdown Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (NB monitor tank transfer pump motor cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	A
Pump casing (holdup tank transfer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Pump casing (NB monitor tank transfer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A

Table 3.4.2-9 Steam and Power Conversion System - Nuclear Blowdown Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (spent resin sluicing)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Resin trap body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Tank (holdup)	LB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VIII.F.S-401	3.4.1-066	A
				Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.29)	VIII.F.S-414	3.4.1-067	A
Tank (NB monitor)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	C
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	C
Tank (spent resin storage)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	C
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	C

Table 3.4.2-9 Steam and Power Conversion System - Nuclear Blowdown Processing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	A

Table 3.4.2-9 Plant-Specific Notes: None

Table 3.4.2-10 Steam and Power Conversion System - Steam Generator Blowdown - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Filter housing (steam generator wet layup)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Flexible hose	LB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-428	3.4.1-077	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-471	3.4.1-122	A
			(I) Treated water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.F.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Flow indicator (body)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-479	3.4.1-131	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
					Selective Leaching (B2.1.21)	VIII.F.SP-55	3.4.1-033	A

Table 3.4.2-10 Steam and Power Conversion System - Steam Generator Blowdown - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Insulation (containment penetration)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-403	3.4.1-064	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.G.S-16	3.4.1-005	A
						VIII.G.S-408	3.4.1-060	A
Pump casing (steam generator wet layup)	LB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	A
					Selective Leaching (B2.1.21)	VIII.F.SP-27	3.4.1-033	A

Table 3.4.2-10 Steam and Power Conversion System - Steam Generator Blowdown - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.F.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	A

Table 3.4.2-10 Plant-Specific Notes: None

Table 3.4.2-11 Steam and Power Conversion System - Turbine Cycle Chemical Feed - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VIII.H.S-421	3.4.1-073	A
				Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Level glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Treated water	None	None	VIII.I.SP-35	3.4.1-055	A
Level glass (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Oil trap	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (condensate alternate injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1

Table 3.4.2-11 Steam and Power Conversion System - Turbine Cycle Chemical Feed - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (condensate ammonia injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Pump casing (condensate hydrazine injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Pump casing (steam generator ammonia injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Pump casing (steam generator hydrazine injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
Tank (condensate ammonia injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	C
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-162	3.4.1-083	E, 1
Tank (condensate hydrazine injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	C
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-162	3.4.1-083	E, 1

Table 3.4.2-11 Steam and Power Conversion System - Turbine Cycle Chemical Feed - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (steam generator standby ammonia injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	C
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-162	3.4.1-083	E, 1
Tank (steam generator standby hydrazine injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	C
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-162	3.4.1-083	E, 1
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.4.2-11 Plant-Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program has been substituted for the Water Chemistry (B2.1.2) program and the One-Time Inspection (B2.1.20) program to manage the applicable aging effects for chemical treatment components.

Table 3.4.2-12 Steam and Power Conversion System - Turbine Cycle Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
Pump casing (sample recovery tank transfer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
Sample element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A

Table 3.4.2-12 Steam and Power Conversion System - Turbine Cycle Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (sample recovery)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-162	3.4.1-083	A
					Water Chemistry (B2.1.2)	VIII.E.SP-162	3.4.1-083	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A

Table 3.4.2-12 Plant-Specific Notes: None

Tables 3.4.2-1 through 3.4.2-12 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

F. Material not in NUREG-2191 for this component.

G. Environment not in NUREG-2191 for this component and material.

H. Aging effect not in NUREG-2191 for this component, material and environment combination.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

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3.5 AGING MANAGEMENT OF CONTAINMENT, STRUCTURES AND COMPONENT SUPPORTS

3.5.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.4, Scoping and Screening Results: Structures, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Reactor Building (Section 2.4.1.1)
- Auxiliary Building (Section 2.4.1.2)
- Auxiliary Service Building (Section 2.4.1.3)
- Circulating Water Intake Structure (Section 2.4.1.4)
- Component Supports (Section 2.4.1.5)
- Control Building (Section 2.4.1.6)
- Diesel Generator Building (Section 2.4.1.7)
- Duct Banks (Section 2.4.1.8)
- Earthen Embankments (Section 2.4.1.9)
- Electrical Manholes (Section 2.4.1.10)
- Electrical Substation and Transformer Areas (Section 2.4.1.11)
- Fuel Handling Building (Section 2.4.1.12)
- Intermediate Building (Section 2.4.1.13)
- Miscellaneous Structural Commodities (Section 2.4.1.14)
- NSSS Supports (Section 2.4.1.15)
- Service Water Discharge Structure (Section 2.4.1.16)
- Service Water Intake Structure (Section 2.4.1.17)
- Service Water Pumphouse (Section 2.4.1.18)
- Tank and Equipment Foundations (Section 2.4.1.19)
- Turbine Building (Section 2.4.1.20)
- Water Treatment Building (Section 2.4.1.21)

3.5.2 RESULTS

The following table summarize the results of the aging management review for Containment, Structures and Component Supports.

- Table 3.5.2-1, Containment Structure - Aging Management Evaluation
- Table 3.5.2-2, Structures and Component Supports - Auxiliary Building - Aging Management Evaluation
- Table 3.5.2-3, Structures and Component Supports - Auxiliary Service Building - Aging Management Evaluation
- Table 3.5.2-4, Structures and Component Supports - Circulating Water Intake Structure - Aging Management Evaluation
- Table 3.5.2-5, Structures and Component Supports - Component Supports - Aging Management Evaluation
- Table 3.5.2-6, Structures and Component Supports - Control Building - Aging Management Evaluation
- Table 3.5.2-7, Structures and Component Supports - Diesel Generator Building - Aging Management Evaluation
- Table 3.5.2-8, Structures and Component Supports - Duct Banks - Aging Management Evaluation
- Table 3.5.2-9, Structures and Component Supports - Earthen Embankments - Aging Management Evaluation
- Table 3.5.2-10, Structures and Component Supports - Electrical Manholes - Aging Management Evaluation
- Table 3.5.2-11, Structures and Component Supports - Electrical Substation and Transformer Areas - Aging Management Evaluation
- Table 3.5.2-12, Structures and Component Supports - Fuel Handling Building - Aging Management Evaluation
- Table 3.5.2-13, Structures and Component Supports - Intermediate Building - Aging Management Evaluation
- Table 3.5.2-14, Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation
- Table 3.5.2-15, Structures and Component Supports - NSSS Supports - Aging Management Evaluation
- Table 3.5.2-16, Structures and Component Supports - Service Water Discharge Structure - Aging Management Evaluation

3.5.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.5.2.1.1 Reactor Building

Materials

The materials of construction for the Reactor Building structural members are:

- Coatings
- Concrete
- Dissimilar metal welds
- Elastomer, rubber and other similar materials
- Reinforced concrete
- Stainless steel
- Steel

Environment

The Reactor Building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater
- Soil
- Treated borated water
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the Reactor Building structural members, require management:

- Cracking
- Cumulative fatigue damage
- Increase in porosity and permeability
- Loss of bond
- Loss of coating or lining integrity
- Loss of leak tightness
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of prestress
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Building structural members:

- 10 CFR Part 50, Appendix J (B2.1.33)
- ASME Section XI, Subsection IWE (B2.1.30)
- ASME Section XI, Subsection IWL (B2.1.31)
- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Protective Coating Monitoring and Maintenance (B2.1.37)
- Structures Monitoring (B2.1.35)
- Water Chemistry (B2.1.2)

3.5.2.1.2 Auxiliary Building

Materials

The materials of construction for the Auxiliary Building structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Reinforced concrete
- Stainless steel
- Steel

Environment

The Auxiliary Building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Auxiliary Building structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Auxiliary Building structural members:

- 10 CFR Part 50, Appendix J (B2.1.33)
- ASME Section XI, Subsection IWE (B2.1.30)
- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.34)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)
- Structures Monitoring (B2.1.35)

3.5.2.1.3 Auxiliary Service Building

Materials

The materials of construction for the Auxiliary Service Building structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The Auxiliary Service Building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Auxiliary Service Building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the Auxiliary Service Building structural members:

- Masonry Walls (B2.1.34)
- Structures Monitoring (B2.1.35)

3.5.2.1.4 Circulating Water Intake Structure

Materials

The materials of construction for the Circulating Water Intake Structure structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Masonry walls
- Reinforced concrete
- Steel

Environment

The Circulating Water Intake Structure structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the Circulating Water Intake Structure structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the Circulating Water Intake Structure structural members:

- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.34)
- Structures Monitoring (B2.1.35)

3.5.2.1.5 Component Supports

Materials

The materials of construction for the Component Supports subcomponents are:

- Aluminum
- Grout
- Lubrite
- Non-metallic (e.g., rubber)
- Stainless steel
- Steel

Environment

The Component Supports subcomponents are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Raw water

Aging Effects Requiring Management

The following aging effects, associated with the Component Supports subcomponents, require management:

- Cracking
- Loss of material
- Loss of mechanical function
- Loss of preload
- Reduction in concrete anchor capacity
- Reduction or loss of isolation function

Aging Management Programs

The following aging management programs manage the aging effects for the Component Supports subcomponents:

- ASME Section XI, Subsection IWF (B2.1.32)
- Boric Acid Corrosion (B2.1.4)
- Structures Monitoring (B2.1.35)

3.5.2.1.6 Control Building

Materials

The materials of construction for the Control Building structural members are:

- Concrete
- Elastomer, rubber and other similar materials
- Reinforced concrete
- Steel

Environment

The Control Building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Control Building structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Control Building structural members:

- Fire Protection (B2.1.15)
- Structures Monitoring (B2.1.35)

3.5.2.1.7 Diesel Generator Building

Materials

The materials of construction for the Diesel Generator Building structural members are:

- Aluminum
- Concrete
- Elastomer, rubber and other similar materials
- Reinforced concrete
- Steel

Environment

The Diesel Generator Building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Diesel Generator Building structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Diesel Generator Building structural members:

- Fire Protection (B2.1.15)
- Structures Monitoring (B2.1.35)

3.5.2.1.8 Duct Banks

Materials

The materials of construction for the Duct Banks structural members are:

- Concrete

Environment

The Duct Banks structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Duct Banks structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Duct Banks structural members:

- Structures Monitoring (B2.1.35)

3.5.2.1.9 Earthen Embankments

Materials

The materials of construction for the Earthen Embankments structural members are:

- Earthfill (rip-rap, stone, soil)

Environment

The Duct Banks structural members are exposed to the following environments:

- Air – outdoor
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the Earthen Embankments structural members, require management:

- Loss of form
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the Earthen Embankments structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)

3.5.2.1.10 Electrical Manholes

Materials

The materials of construction for the Electrical Manholes structural members are:

- Concrete
- Steel

Environment

The Electrical Manholes structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Electrical Manholes structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Electrical Manholes structural members:

- Structures Monitoring (B2.1.35)

3.5.2.1.11 Electrical Substation and Transformer Areas

Materials

The materials of construction for the Electrical Substation and Transformer Areas structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The Electrical Substation and Transformer Areas structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Electrical Substation and Transformer Areas structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Electrical Substation and Transformer Areas structural members:

- Masonry Walls (B2.1.34)
- Structures Monitoring (B2.1.35)

3.5.2.1.12 Fuel Handling Building

Materials

The materials of construction for the Fuel Handling Building structural members are:

- Aluminum
- Boral; boron steel, and other materials (excluding Boraflex)
- Concrete
- Elastomer, rubber and other similar materials
- Reinforced concrete
- Stainless steel
- Steel

Environment

The Fuel Handling Building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater
- Soil
- Treated borated water
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Fuel Handling Building structural members, require management:

- Change in dimensions and loss of material
- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of neutron-absorbing capacity

Aging Management Programs

The following aging management programs manage the aging effects for the Fuel Handling Building structural members:

- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B2.1.27)
- Structures Monitoring (B2.1.35)
- Water Chemistry (B2.1.2)

3.5.2.1.13 Intermediate Building

Materials

The materials of construction for the Intermediate Building structural members are:

- Aluminum
- Concrete
- Elastomer, rubber and other similar materials
- Reinforced concrete
- Steel

Environment

The Intermediate Building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Intermediate Building structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Intermediate Building structural members:

- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Structures Monitoring (B2.1.35)

3.5.2.1.14 Miscellaneous Structural Commodities

Materials

The materials of construction for the Miscellaneous Structural Commodities Subcomponents are:

- Cementitious coatings (Pyrocrete, BIO® K-10 Mortar, Cafecote, and other similar materials)
- Elastomer
- Elastomer, rubber and other similar materials
- Silicates (Marinite®, Kaowool®, Cerafiber®, Cera® blanket, or other similar materials)
- Stainless steel
- Steel
- Subliming compounds (Thermo-lag®, Darmatt®, 3M® Interam®, and other similar materials)

Environment

The Miscellaneous Structural Commodities Subcomponents subcomponents are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the Miscellaneous Structural Commodities Subcomponents subcomponents, require management:

- Change in material properties
- Cracking
- Cracking/delamination
- Hardening, loss of strength, shrinkage
- Loss of material
- Loss of preload
- Loss of sealing
- Separation

Aging Management Programs

The following aging management programs manage the aging effects for the Miscellaneous Structural Commodities Subcomponents subcomponents:

- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Structures Monitoring (B2.1.35)

3.5.2.1.15 NSSS Supports

Materials

The materials of construction for the NSSS Supports subcomponents are:

- Grout
- High-strength steel
- Lubrite
- Stainless steel
- Steel

Environment

The NSSS Supports subcomponents are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects, associated with the NSSS Supports subcomponents, require management:

- Cracking
- Loss of material
- Loss of mechanical function
- Loss of preload
- Reduction in concrete anchor capacity

Aging Management Programs

The following aging management programs manage the aging effects for the NSSS Supports subcomponents:

- ASME Section XI, Subsection IWF (B2.1.32)
- Boric Acid Corrosion (B2.1.4)
- Structures Monitoring (B2.1.35)

3.5.2.1.16 Service Water Discharge Structure

Materials

The materials of construction for the Service Water Discharge Structure structural members are:

- Concrete

Environment

The Service Water Discharge Structure structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Service Water Discharge Structure structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the Service Water Discharge Structure structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)
- Structures Monitoring (B2.1.35)

3.5.2.1.17 Service Water Intake Structure

Materials

The materials of construction for the Service Water Intake Structure structural members are:

- Concrete
- Steel

Environment

The Service Water Intake Structure structural members are exposed to the following environments:

- Groundwater
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the Service Water Intake Structure structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the Service Water Intake Structure structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)
- Structures Monitoring (B2.1.35)

3.5.2.1.18 Service Water Pumphouse

Materials

The materials of construction for the Service Water Pumphouse structural members are:

- Aluminum
- Concrete
- Reinforced concrete
- Steel

Environment

The Service Water Pumphouse structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the Service Water Pumphouse structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the Service Water Pumphouse structural members:

- Fire Protection (B2.1.15)
- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)
- Structures Monitoring (B2.1.35)

3.5.2.1.19 Tank and Equipment Foundations

Materials

The materials of construction for the Tank and Equipment Foundations structural members are:

- Concrete
- Elastomer, rubber and other similar materials
- Steel

Environment

The Tank and Equipment Foundations structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Tank and Equipment Foundations structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Tank and Equipment Foundations structural members:

- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)
- Structures Monitoring (B2.1.35)

3.5.2.1.20 Turbine Building

Materials

The materials of construction for the Turbine Building structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Masonry walls
- Reinforced concrete
- Steel

Environment

The Turbine Building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Turbine Building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the Turbine Building structural members:

- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.34)
- Structures Monitoring (B2.1.35)

3.5.2.1.21 Water Treatment Building

Materials

The materials of construction for the Water Treatment Building structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The Water Treatment Building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the Water Treatment Building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the Water Treatment Building structural members:

- Masonry Walls (B2.1.34)
- Structures Monitoring (B2.1.35)

3.5.2.2 Further Evaluation of Aging Management as Recommended by NUREG-2192

NUREG-2192 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the Subsequent License Renewal Application. For the containment, structures and component supports, those evaluations are addressed in the following sections.

NOTE: Reactor Building is the site-specific term used for Containment; therefore, these terms are interchangeable.

3.5.2.2.1.1 Cracking and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, and Cracking Due to Differential Settlement and Erosion of Porous Concrete Subfoundations

Cracking and distortion due to increased stress levels from settlement could occur in PWR and BWR concrete and steel containments. The existing program relies on ASME Code, Section XI, Subsection IWL to manage these aging effects. Also, reduction of foundation strength and cracking, due to differential settlement and erosion of porous concrete subfoundations could occur in all types of PWR and BWR containments. The existing program relies on the structures monitoring program to manage these aging effects. However, some plants may rely on a dewatering system to lower the site groundwater level. If the plant's current licensing basis (CLB) credits a dewatering system to control settlement, further evaluation is recommended to verify the continued functionality of the dewatering system during the subsequent period of extended operation.

[3.5.1-001] [3.5.1-002] - Not applicable.

The Reactor Building foundation mat is supported by fill concrete that extends down to competent rock. The Reactor Building foundation design does not incorporate porous concrete in the sub-foundation. In 2008, a dewatering system was installed in proximity to the plant structures experiencing water intrusion issues. Settlement of adjoining buildings and structures was evaluated in advance and monitored during the incremental drawdown of the water table. However, the plant's current licensing basis does not credit a dewatering system to control settlement.

Accessible concrete components are monitored by the Structures Monitoring (B2.1.35) program for components within the scope of the Structures Monitoring (B2.1.35) program or the ASME Section XI, Subsection IWL (B2.1.31) program for components within the scope of the ASME Section XI, Subsection IWL (B2.1.31) program to confirm the absence of any visible effects due to settlement. Plant operating experience has not identified cracking or distortion of the Reactor Building concrete elements due to settlement.

3.5.2.2.1.2 Reduction of Strength and Modulus Due to Elevated Temperature

Reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR concrete and steel containments. The implementation of 10 CFR 50.55a and ASME Code, Section XI, Subsection IWL would not be able to identify the reduction of strength and modulus of concrete due to elevated temperature. Subsection CC-3440 of ASME Code, Section III, Division 2, specifies the concrete temperature limits for normal operation or any other long-term period. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code, Section XI, Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging effects for portions of the concrete containment components that exceed specified temperature limits {i.e., general area temperature greater than 66 degrees Celsius (150 degrees Fahrenheit) and local area temperature greater than 93 degrees Celsius (200 degrees Fahrenheit)}. Higher temperatures may be allowed if tests and/or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. Acceptance criteria are described in Branch Technical Position (BTP) RLSB (License Renewal and Standardization Branch)-1, "Aging Management Review - Generic, July 2017" (Appendix A.1 of this SRP-SLR).

[3.5.1-003] - Not applicable.

FSAR Section 3.8.1.3.1.3 discusses pipe penetrations and the design of the Reactor Building liner. FSAR Section 3.8.1.3.1.3 notes that operating temperature range of 50°F to 120°F inside the Reactor Building is considered in the design, and that concrete temperature is limited to 200°F, maximum, at such local spots. Additionally, FSAR Section 3.8.1.5.1.2 states that the temperature in the Reactor Building concrete is limited to 150°F, except in local areas such as pipe penetration locations where 200°F is the limitation. Therefore, the Reactor Building concrete will not exceed the ASME Code specified limits of 150°F for general areas and 200°F locally.

Plant operating experience has not identified any aging effects for Reactor Building concrete related to elevated temperature. Therefore, the aging effects due to elevated temperatures are not applicable, and a plant-specific aging management program or plant-specific enhancements to ASME Section XI, Subsection IWL and/or Structures Monitoring aging management programs are not required.

3.5.2.2.1.3 Loss of Material Due to General, Pitting and Crevice Corrosion

(1) Loss of material due to general, pitting, and crevice corrosion could occur in steel elements of inaccessible areas for all types of PWR and BWR containments. The existing program relies on ASME Code, Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J AMPs, to manage this aging effect. Further evaluation is recommended of plant-specific programs to manage this aging effect if corrosion is indicated from the IWE examinations. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

(1) [3.5.1-005] [3.5.1-035] - The ASME Section XI, Subsection IWE (B2.1.30) program manages aging of the Reactor Building steel liner, which includes liner anchors and integral attachments. The 10 CFR Part 50, Appendix J (B2.1.33) program manages loss of leak tightness, loss of sealing, and leakage through Reactor Building liner to assure that allowable leakage rate limits specified in the Technical Specifications are not exceeded. An evaluation of the acceptability of the inaccessible areas is completed whenever conditions are detected in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. A review of plant operating experience associated with accessible areas from the ASME Section XI, Subsection IWE (B2.1.30) program has identified indications of corrosion, which have been evaluated for continued service or otherwise addressed by the corrective action program. However, the identified indications have not resulted in a loss of intended functions.

The ASME Section XI, Subsection IWE (B2.1.30) program includes augmented examinations of the guard pipes that lead to isolation valve chambers that are associated with residual heat removal and reactor building spray. These components are located in the Auxiliary Building and are considered to be extensions of the containment pressure boundary. Plant-specific operating experience has identified coating degradation and corrosion of these guard pipes. Groundwater leaks into the annulus space between the guard piping and the surrounding concrete wall pipe sleeve, resulting in degradation of the guard pipe coating, and subsequently the exterior carbon steel surface. The ASME Section XI, Subsection IWE (B2.1.30) program also includes augmented examinations of the accessible areas of containment moisture barrier, at the Reactor Building liner/floor perimeter interface. Damage to the moisture barrier or debonding of the sealant from the liner at some locations has been observed during previous inspections.

The Reactor Building concrete was designed in accordance with ACI 318-71 and constructed in accordance with ACI 301-72 using ingredients conforming to ACI and ASTM standards which provide a good quality, dense, low permeability concrete to protect against corrosion. The concrete mix proportions were established in accordance with ACI 301-72. An air-entraining agent, which conformed to the requirements of ASTM C260, was used in an amount sufficient to entrain four to eight percent of air. Additionally, a water reducing admixture complying with ASTM C494 was used. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The ASME Section XI, Subsection IWL (B2.1.31) program and the Structures Monitoring (B2.1.35) program identify and manage any cracks in the Reactor Building concrete that could potentially provide a pathway for water to reach inaccessible portions of the Reactor Building liner. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI 318. Therefore, a plant-specific aging management program to manage loss of material due to general, pitting and crevice corrosion for steel elements in inaccessible areas is not required.

(2) Not applicable - BWR only.

(3) Not applicable - BWR only.

3.5.2.2.1.4 Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature

Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for PWR prestressed concrete containments and BWR Mark II prestressed concrete containments is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.5, "Concrete Containment Unbonded Tendon Pre-stress Analysis," and/or Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR.

[3.5.1-008] - Loss of prestress with the Reactor Building tendons is a TLAA, as defined in 10 CFR 54.3. Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for the Reactor Building tendons is addressed in Section 4.5, Concrete Containment Tendon Prestress Analysis.

3.5.2.2.1.5 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue, cyclical loading, or cyclical displacement of metal liner, metal plates, suppression pool steel shells (including welded joints) and penetrations (including personnel airlock, equipment hatch, control rod drive (CRD) hatch, penetration sleeves, dissimilar metal welds, and penetration bellows) for all types of PWR and BWR containments and BWR vent header, vent line bellows, and downcomers may be TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed in Section 4.6, "Containment Liner Plates, Metal Containments, and Penetrations Fatigue Analysis," and for cases of plant specific components, in Section 4.7 "Other Plant Specific Time-Limited Aging Analyses," of this SRP SLR. For plant-specific cumulative usage factor calculations, the method used is appropriately defined and discussed in the applicable TLAAs.

For the above-stated containment pressure-retaining components (corresponding to Table 3.5-1, Items 027 and 040) subject to cyclic loading for which no CLB fatigue analysis exists at the time of an SLRA submittal, a plant-specific further evaluation may be performed to demonstrate that cracking due to cyclic loading is an aging effect that does not require aging management for the component. As one acceptable approach, the aging effect does not require aging management actions if the further evaluation demonstrates that the six criteria for cyclic loading in paragraph NE-3222.4(d) (NE-3221.5(d) in 1980 and later code editions), "Analysis for Cyclic Operation, Vessels Not Requiring Analysis for Cyclic Service," of ASME Code, Section III, Division 1 (1974 edition or later edition incorporated by reference in 10 CFR 50.55a(a)(i)), that provide for a waiver from detailed fatigue analysis are satisfied for applicable component materials through the end of the subsequent period of extended operation. The option to perform a fatigue waiver analysis to address the aging effect of cracking due to cyclic loading, for specific containment metallic components, is in lieu of performing supplemental surface examinations or performing or crediting an appropriate 10 CFR Part 50, Appendix J, leak-rate test discussed in GALL-SLR Report AMP XI.S1, "ASME Section XI, Subsection IWE."

[3.5.1-009] - The evaluation of the Reactor Building liner plate fatigue is addressed as a TLAA in SLRA Section 4.6.1, Containment Liner Plate. Cumulative fatigue damage of the Reactor Building main steam containment penetrations is addressed as a TLAA in SLRA Section 4.6.3, Containment Penetrations Fatigue Analysis.

[3.5.1-027] - Fatigue waivers were performed for electrical penetrations, penetration sleeves, personnel access airlock, personnel escape airlock, equipment hatch, and the residual heat removal and containment spray isolation valve containers to address the aging effect of cracking due to cyclic loading. These fatigue waivers were based upon the numbers of projected cycles that bound 80 years of plant operation and demonstrate that no fatigue analysis is required for these components. Therefore, cracking due to cyclic loading is an aging effect that does not require aging management.

Fatigue analyses were performed for the containment pressure-retaining components within the penetration assemblies which connect the process pipe to the penetration sleeves (e.g., cylindrical extensions of the penetration sleeves and the flat plate that attaches to the process pipe). Fatigue analyses were also performed for the pipe caps attached to the end of penetration sleeves for spare penetrations. These fatigue analyses were determined to remain valid for 80 years of plant operation and demonstrate that, for these components, cracking due to cyclic loading is an aging effect that does not require aging management.

The fuel transfer tube connects the refueling canal inside the Reactor Building with the fuel transfer canal in the Fuel Handling Building, and functions as the pathway for moving fuel assemblies into and out of the Reactor Building. The pressure retaining portions of the fuel transfer tube assemblies that are integral with the containment pressure boundary include the fuel transfer tube, blind flange, and the penetration sleeve. Expansion bellows, which are not part of the containment pressure boundary, are attached to fuel transfer tube assemblies in both the Reactor Building and the Fuel Handling Building. These bellows permit the fuel transfer tube assemblies to expand and contract. Since the fuel transfer tube assemblies are allowed to freely expand and contract, these components are not subject to significant cyclic loads. Therefore, for the fuel transfer tube assemblies that are integral with the containment pressure boundary, cracking due to cyclic loading is an aging effect that does not require aging management.

NUREG-2191, Section X1.S1, ASME Section XI, Subsection IWE notes that Appendix J leak rate tests capable of detection of cracking may be performed or credited in lieu of the supplemental surface examinations. 10 CFR Part 50, Appendix J Type B local leak rate tests capable of detecting cracking due cyclic loading are performed by 10 CFR Part 50, Appendix J (B2.1.33) program for the guard piping and bellows associated with the residual heat removal and containment spray isolation valve containers. Therefore, supplemental surface examinations will not be required for these components.

Containment pressure-retaining components that are subject to cyclic loading, but have no CLB fatigue analysis, have been addressed as described above; therefore, supplemental surface examination (or other applicable technique) will not be required for these components.

[3.5.1-040] - Not applicable - BWR only.

3.5.2.2.1.6 Cracking Due to Stress Corrosion Cracking

Stress corrosion cracking (SCC) of stainless steel (SS) penetration sleeves, penetration bellows, vent line bellows, suppression chamber shell (interior surface), and dissimilar metal welds could occur in PWR and/or BWR containments. The existing program relies on ASME Code, Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, to manage this aging effect. Further evaluation, including consideration of SCC susceptibility and applicable operating experience (OE) related to detection, is recommended of additional appropriate examinations/evaluations implemented to detect this aging effect for these SS components and dissimilar metal welds.

[3.5.1-010] - Stainless steel penetration sleeves, stainless steel penetration bellows, dissimilar metal welds, and stainless steel fuel transfer tube assemblies are part of the containment pressure boundary. The ASME Section XI, Subsection IWE (B2.1.30) program and the 10 CFR Part 50, Appendix J (B2.1.33) program manage the aging of penetration sleeves, stainless steel penetration bellows, dissimilar metal welds, and fuel transfer tube assemblies. Stainless steel components and dissimilar metal welds exposed to temperatures greater than 140°F and/or an aggressive chemical (e.g. exposure to chlorides, halides) environment are potentially susceptible to SCC.

Plant operating experience has not identified SCC associated with these components. In the Fall 2021 refueling outage (RF26), surface examinations were performed on dissimilar metal welds associated with four Reactor Building piping penetrations with design operating temperatures greater than or equal to 140°F. The four dissimilar metal welds were determined to be a representative 20% sample of the penetration dissimilar metal welds that were most susceptible to cracking due to SCC. The surface examinations of the four penetration dissimilar metal welds did not identify cracking.

Visual examinations will be supplemented with surface examinations (or other applicable technique, e.g., EVT-1) to manage cracking due to SCC for stainless steel and dissimilar metal welds in containment pressure retaining components associated with the fuel transfer tube assemblies and piping penetration sleeves exposed to high operating temperatures (i.e., temperatures greater than or equal to 140°F). The supplemental examinations will be one-time inspections that will be performed before entering the subsequent period of extended operation. For the stainless steel penetrations and dissimilar metal welds associated with high operating temperature piping systems, consistent with the guidance of NUREG-2191, a representative sample size of 20 percent of the population will be subject to the supplemental examinations. The one-time supplemental surface examinations (or other applicable technique, e.g., EVT-1) will be incorporated into the ASME Section XI, Subsection IWE (B2.1.30) program to confirm the absence of cracking due to SCC. If SCC is detected as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the Corrective Action Program.

The stainless steel and dissimilar metal welds associated with the electrical penetrations are not exposed to an environment that is conducive to SCC. The temperatures that the electrical penetrations are exposed to, both internal and external to the Reactor Building, are less than 140°F. Additionally, the environment in these areas is indoor air. A review of plant operating experience did not identify cracking of stainless steel components in air environments. Therefore, stainless steel associated with Reactor Building electrical penetrations will not be subject to supplemental surface examinations to manage potential cracking due to SCC.

NUREG-2191, Section X1.S1, ASME Section XI, Subsection IWE notes that Appendix J leak rate tests capable of detection of cracking may be performed or credited in lieu of the supplemental surface examinations. The 10 CFR Part 50, Appendix J (B2.1.33) program performs periodic Type B local leak rate tests on the stainless steel bellows, dissimilar metal welds, and stainless steel materials associated with the residual heat removal and containment spray isolation valve containers and guard pipe assemblies. The guard pipes are sealed in the Reactor Building recirculation sumps by a flat plate welded to the penetration sleeve and the process pipe to form the containment liner seal. These Type B local leak rate tests, which are capable of detecting cracking due SCC, test the volume enclosed by the isolation valve containers, stainless steel bellows, guard pipe, and the flat plate between the penetration sleeve and the process pipe. Therefore, supplemental surface examinations will not be required for these components.

3.5.2.2.1.7 Loss of Material (Scaling, Spalling) and Cracking Due to Freeze-Thaw

Loss of material (scaling, spalling) and cracking due to freeze-thaw could occur in inaccessible areas of PWR and BWR concrete containments. Further evaluation is recommended to determine the need for a plant specific AMP or plant-specific enhancements to ASME Code, Section XI, Subsection IWL, and/or Structures Monitoring AMPs, to manage these aging effects for plants located in moderate to severe weathering conditions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

[3.5.1-011] - The plant is located in a moderate weathering region, as defined in ASTM C33. Reinforced concrete for the Reactor Building was designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. The concrete mix designs for the Reactor Building contained an air-entraining admixture capable of entraining four to eight percent air. Procedural controls ensured quality throughout the batching, mixing, and placement processes. Plant operating experience has not identified any aging effects related to freeze-thaw in accessible areas and the Structures Monitoring (B2.1.35) program and the ASME Section XI, Subsection IWL (B2.1.31) program confirm the absence of aging effects by examining normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. Therefore, a plant-specific aging management program or plant-specific enhancements to ASME Section XI, Subsection IWL and/or Structures Monitoring aging management programs are not required for inaccessible areas to manage loss of material and cracking due to freeze-thaw.

3.5.2.2.1.8 Cracking Due to Expansion From Reaction With Aggregates

Cracking due to expansion from reaction with aggregates could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. The GALL-SLR Report recommends further evaluation to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code, Section XI, Subsection IWL, and/or Structures Monitoring AMPs, to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

[3.5.1-012] - Concrete inspectors are trained to identify changes that could be indicative of Alkali-Silica Reaction (ASR). The training includes the conditions and indications of degradation identified in ACI 201.1R and ACI 349.3R. In addition, concrete monitoring includes inspection of concrete for cracking; general signs of settlement, movement, or distortion; and seismic gaps are inspected for closure of gap due to settlement or movement. Potential indications of ASR development will be entered into the Corrective Action Program and will be evaluated by the responsible engineer. If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the ASME Section XI, Subsection IWL (B2.1.31) program, the Structures Monitoring (B2.1.35) program, or the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program.

Plant-specific operating experience has not identified any indications of ASR for concrete. The ASME Section XI, Subsection IWL (B2.1.31) program and the Structures Monitoring (B2.1.35) program require that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Additionally, areas normally considered inaccessible are inspected by the Structures Monitoring (B2.1.35) program when other plant activities such as scheduled maintenance work or plant modifications permit access. Therefore, a plant-specific aging management program or plant-specific enhancements to ASME Section XI, Subsection IWL and/or Structures Monitoring aging management programs for inaccessible areas are not required to manage cracking due to expansion from reaction with aggregates.

3.5.2.2.1.9 Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide and Carbonation

Increase in porosity and permeability due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code, Section XI, Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging effects if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

[3.5.1-014] - Reinforced concrete for the Reactor Building was designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI 318. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The ASME Section XI, Subsection IWL (B2.1.31) program and the Structures Monitoring (B2.1.35) program identify and manage any cracks in the Reactor Building concrete. The Structures Monitoring (B2.1.35) program and the ASME Section XI, Subsection IWL (B2.1.31) program inspect for evidence of leaching of calcium hydroxide and carbonation in accessible, and normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. The Structures Monitoring (B2.1.35) program and the ASME Section XI, Subsection IWL (B2.1.31) program require that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Although plant operating experience has identified evidence of leaching of calcium hydroxide, it has been determined that the observed leaching did not adversely impact the structural integrity or result in a loss of intended function of in-scope structures. Therefore, a plant-specific aging management program or plant-specific enhancements to ASME Section XI, Subsection IWL and/or Structures Monitoring aging management programs for inaccessible areas to manage the effects of increase in porosity and permeability due to leaching of calcium hydroxide and carbonation are not required.

3.5.2.2.2.1 Aging Management of Inaccessible Areas

(1) Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Groups 1-3, 5 and 7-9 structures. Further evaluation is recommended of inaccessible areas of these Groups of structures for plants located in moderate to severe weathering conditions to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

(1) [3.5.1-042] - Freeze-Thaw - Reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI 318. Procedural controls ensured quality throughout the batching, mixing, and placement processes. These ACI codes provide guidance on entraining air into the concrete mix for concrete structures potentially exposed to freezing and thawing conditions.

Plant operating experience has not identified any aging effects related to freeze-thaw in accessible areas and the Structures Monitoring (B2.1.35) program confirms the absence of aging effects by examining normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. Therefore, a plant-specific aging management program or plant-specific enhancements to the Structures Monitoring aging management program for inaccessible areas are not required to manage loss of material and cracking due to freeze-thaw.

(2) Cracking due to expansion and reaction with aggregates could occur in inaccessible concrete areas for Groups 1-5 and 7-9 structures. Further evaluation is recommended of inaccessible areas of these Groups of structures to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

(2) [3.5.1-043] - Alkali-Silica Reaction (ASR) - Concrete inspectors are trained to identify changes that could be indicative of Alkali-Silica Reaction (ASR). The training includes the conditions and indications of degradation identified in ACI 201.1R and ACI 349.3R. In addition, concrete monitoring includes inspection of concrete for cracking; general signs of settlement, movement, or distortion; and seismic gaps are inspected for closure of gap due to settlement or movement. Potential indications of ASR development will be entered into the Corrective Action Program and will be evaluated by the responsible engineer. If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the ASME Section XI, Subsection IWL (B2.1.31) program, the Structures Monitoring (B2.1.35) program, or the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program.

Plant operating experience has not identified any indications of ASR for concrete. The Structures Monitoring (B2.1.35) program requires that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Additionally, areas normally considered inaccessible are inspected by the Structures Monitoring (B2.1.35) program when other plant activities such as scheduled maintenance work or plant modifications permit access. Therefore, a plant-specific aging management program or plant-specific enhancements to the Structures Monitoring aging management program for inaccessible areas are not required to manage cracking due to expansion from reaction with aggregates.

(3) Cracking and distortion due to increased stress levels from settlement could occur in below-grade inaccessible concrete areas of structures for all Groups, and reduction in foundation strength, and cracking due to differential settlement and erosion of porous concrete subfoundations could occur in below-grade inaccessible concrete areas of Groups 1-3, 5-9 structures. The existing program relies on structure monitoring programs to manage these aging effects. Some plants may rely on a dewatering system to lower the site groundwater level. If the plant's CLB credits a dewatering system, verification is recommended of the continued functionality of the dewatering system during the subsequent period of extended operation. No further evaluation is recommended if this activity is included in the scope of the applicant's structures monitoring program.

(3) [3.5.1-044] [3.5.1-046] - Settlement - As described in FSAR Section 2.4.13.2.7, a dewatering system was installed in 2008 in the proximity to plant structures that were experiencing water intrusion issues. During implementation, settlement of adjoining buildings and structures was evaluated in advance and monitored during the incremental drawdown of the water table. Following stabilization of the ground water regime, observed displacements were within acceptable limits established in the structural evaluation (i.e., settlement was not structurally significant). However, the plant's current licensing basis does not credit a dewatering system to control settlement.

As described in FSAR Section 18.2.32, survey monitoring of the Service Water Pumphouse, Service Water Intake Structure, electrical Duct Banks, and Service Water Intake Line “A”. The purpose of the surveys is to identify settlement issues prior to their resulting in significant degradation or loss of function. Accessible concrete components of soil founded structures within-scope of subsequent license renewal are monitored by the Structures Monitoring (B2.1.35) program to confirm the absence of any visible effects due to settlement. Additionally, porous concrete was not used for the structure subfoundations.

(4) Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation could occur in below-grade inaccessible concrete areas of Groups 1-5 and 7-9 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRPSLR).

(4) [3.5.1-047] - Leaching - Reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The Structures Monitoring (B2.1.35) program identifies and manages any cracks in the concrete structures. Additionally, the Structures Monitoring (B2.1.35) program inspects for evidence of leaching of calcium hydroxide and carbonation in accessible, and normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. The Structures Monitoring (B2.1.35) program requires that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Although plant operating experience has identified evidence of leaching of calcium hydroxide, it has been determined that the observed leaching did not adversely impact the structural integrity or result in a loss of intended function of the associated concrete structures. Therefore, a plant-specific aging management program or plant-specific enhancements to the Structures Monitoring aging management program for inaccessible areas to manage the effects of increase in porosity and permeability due to leaching of calcium hydroxide and carbonation are not required.

3.5.2.2.2.2 Reduction of Strength and Modulus Due to Elevated Temperature

Reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR Group 1-5 concrete structures. For any concrete elements that exceed specified temperature limits, further evaluations are recommended. Appendix A of American Concrete Institute (ACI) 349-85 specifies the concrete temperature limits for normal operation or any other long-term period. The temperatures shall not exceed 66 degrees Celsius (150 degrees Fahrenheit) except for local areas, which are allowed to have increased temperatures not to exceed 93 degrees Celsius (200 degrees Fahrenheit). Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects if any portion of the safety-related and other concrete structures exceeds specified temperature limits [i.e., general area temperature greater than 66 degrees Celsius (150 degrees Fahrenheit) and local area temperature greater than 93 degrees Celsius (200 degrees Fahrenheit)]. Higher temperatures may be allowed if tests and/or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

[3.5.1-048] - The maximum general area air temperature in the structures is less than 150°F. Hot pipe penetrations in some structures may be subject to temperatures higher than 150°F, but not greater than 200°F. Therefore, concrete temperatures are limited to 150°F, except in local areas such as pipe penetration locations where 200°F is the limitation.

During normal operation the temperature of the spent fuel pool water is maintained between a temperature of 50°F and 120°F. During various refueling operation scenarios (e.g., full core off-load, core shuffle, etc.), the spent fuel pool water temperature may exceed 120°F. However, per Technical Specification 3.9.3, the spent fuel pool cooling system maintains the bulk spent fuel pool temperature below 170°F during the various refueling operation scenarios. Therefore, the concrete temperature will not exceed a temperature of 150°F except during the short-term event of refueling operation scenarios, during which the temperature of the concrete in some areas may reach 170°F.

No other issues related to elevated temperatures affecting concrete structures exposed to air have been identified. Review of operating experience has identified no issues related to elevated temperatures affecting concrete structures. Therefore, the aging effects due to elevated temperatures are not applicable, and a plant-specific aging management program or plant-specific enhancements to Structures Monitoring aging management program are not required.

3.5.2.2.2.3 Aging Management of Inaccessible Areas for Group 6 Structures

Further evaluation is recommended for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below, whether or not they are covered by inspections in accordance with the GALL-SLR Report, AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," or Federal Energy Regulatory Commission (FERC)/U.S. Army Corp of Engineers dam inspection and maintenance procedures.

(1) Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects of this aging effects for inaccessible areas for plants located in moderate to severe weathering conditions. Acceptance criteria are described in BTP RLSB-1 (Appendix A1 of SRP-SLR).

(1) [3.5.1-049] - Freeze-Thaw - Reinforced concrete for water-control structures (Group 6) was designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI 318. Procedural controls ensured quality throughout the batching, mixing, and placement processes. These ACI codes provide guidance on entraining air into the concrete mix for concrete structures potentially exposed to freezing and thawing conditions.

Plant operating experience has not identified any aging effects related to freeze-thaw in accessible areas and the Structures Monitoring (B2.1.35) program confirms the absence of aging effects by examining normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. Therefore, a plant-specific aging management program or plant-specific enhancements to Structures Monitoring aging management program for inaccessible areas are not required to manage loss of material and cracking due to freeze-thaw.

(2) Cracking due to expansion and reaction with aggregates could occur in inaccessible concrete areas of Group 6 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

(2) [3.5.1-050] - Alkali-Silica Reaction (ASR) - Concrete inspectors are trained to identify changes that could be indicative of Alkali-Silica Reaction (ASR). The training includes the conditions and indications of degradation identified in ACI 201.1R and ACI 349.3R. In addition, concrete monitoring includes inspection of concrete for cracking; general signs of settlement, movement, or distortion; and seismic gaps are inspected for closure of gap due to settlement or movement. Potential indications of ASR development will be entered into the Corrective Action Program and will be evaluated by the responsible engineer. If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the ASME Section XI, Subsection IWL (B2.1.31) program, the Structures Monitoring (B2.1.35) program, or the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program.

Plant operating experience has not identified any indications of ASR for concrete. The Structures Monitoring (B2.1.35) program requires that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Additionally, areas normally considered inaccessible are inspected by the Structures Monitoring (B2.1.35) program when other plant activities such as scheduled maintenance work or plant modifications permit access. Therefore, a plant-specific aging management program or plant-specific enhancements to the Structures Monitoring (B2.1.35) program for inaccessible areas are not required to manage cracking due to expansion from reaction with aggregates.

(3) Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of Group 6 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

(3) [3.5.1-051] - Leaching - Water-control structures (Group 6) were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The Structures Monitoring (B2.1.35) program identifies and manages any cracks in the concrete structures. Additionally, the Structures Monitoring (B2.1.35) program inspects for evidence of leaching of calcium hydroxide and carbonation in accessible, and normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. The Structures Monitoring (B2.1.35) program requires that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Although plant operating experience has identified evidence of leaching of calcium hydroxide, it has been determined that the observed leaching did not adversely impact the structural integrity or result in a loss of intended function of the associated concrete structures. Therefore, a plant-specific aging management program or plant-specific enhancements to the Structures Monitoring aging management program for inaccessible areas to manage the effects of increase in porosity and permeability due to leaching of calcium hydroxide and carbonation are not required.

3.5.2.2.2.4 Cracking Due to Stress Corrosion Cracking, and Loss of Material Due to Pitting and Crevice Corrosion

Cracking due to SSC and loss of material due to pitting and crevice corrosion could occur in: (a) Group 7 and 8 SS tank liners exposed to standing water; and (b) SS and aluminum alloy support members; welds; bolted connections; or support anchorage to building structure exposed to air or condensation (see SRP SLR Sections 3.2.2.2.2, 3.2.2.2.4, 3.2.2.2.8, and 3.2.2.2.10 for background information).

For Group 7 and 8 SS tank liners exposed to standing water, further evaluation is recommended of plant-specific programs to manage these aging effects. The acceptance criteria are described in BTP RLSB 1 (Appendix A.1 of this SRP SLR).

For SS and aluminum alloy support members; welds; bolted connections; support anchorage to building structure exposed to air or condensation, the plant specific OE and condition of the SS and aluminum alloy components are evaluated to determine if the plant specific air or condensation environments are aggressive enough to result in loss of material or cracking after prolonged exposure. The aging effects of loss of material and cracking in SS and aluminum alloy components is not applicable and does not require management if: (a) the plant specific OE does not reveal a history of pitting or crevice corrosion or cracking and (b) a one-time inspection demonstrates that the aging effects are not occurring or that an aging effect is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant specific OE review in the SLRA. Visual inspections conducted in accordance with GALL-SLR Report AMP XI.M32, "One Time Inspection," are an acceptable method to demonstrate that the aging effects are not occurring at a rate that affects the intended function of the components. One-time inspections are conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32. If loss of material or cracking has occurred and is sufficient to potentially affect the intended function of SS or aluminum alloy support members; welds; bolted connections; or support anchorage to building structure, either: (a) enhancing the applicable AMP (i.e., GALL-SLR Report AMP XI.S3, "ASME Code, Section XI, Subsection IWF," or AMP XI.S6, "Structures Monitoring"); (b) conducting a representative sample inspection consistent with GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components;" or (c) developing a plant specific AMP are acceptable programs to manage loss of material or cracking (as applicable). Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combinations which are not susceptible to SCC when used in structural support applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. For these alloys and tempers, the susceptibility of cracking due to SCC is not applicable. If these alloys or tempers have been used, the SLRA states the specific alloy or temper used for the applicable in scope components.

[3.5.1-052] - There are no stainless steel tank liners within the scope of subsequent license renewal. The Reactor Building sump liners are stainless steel components exposed to standing water and are aligned to this item. Plant-specific operating experience has not identified loss of material due to pitting or crevice corrosion, or cracking due to SCC for the stainless steel associated with the Reactor Building sump liners. The ASME Section XI, Subsection IWE (B2.1.30) program will manage cracking and loss of material of the Reactor Building sump liners.

[3.5.1-099] - Plant-specific OE has not identified pitting or crevice corrosion or cracking for stainless steel components exposed to air or condensation environment. The ASME Section XI, Subsection IWF (B2.1.32) program will manage the aging of stainless steel component supports to ensure that these components continue to perform their intended functions during the subsequent period of extended operation. There are no aluminum support components that are within the scope of the ASME Section XI, Subsection IWF (B2.1.32) program.

[3.5.1-100] - Plant-specific OE has not identified pitting or crevice corrosion or cracking for stainless steel components exposed to air or condensation environment. The Structures Monitoring (B2.1.35) program will manage the aging of stainless steel and aluminum alloy component supports to ensure that these components continue to perform their intended functions during the subsequent period of extended operation. In addition to Structures and Component Supports, stainless steel components in Auxiliary Systems (materials handling) are aligned to this row with management by the Structures Monitoring (B2.1.35) program.

3.5.2.2.2.5 Cumulative Fatigue Damage Due to Fatigue

Evaluations involving time-dependent fatigue, cyclical loading, or cyclical displacement of component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports are TLAAs as defined in 10 CFR 54.3 only if a CLB fatigue analysis exists. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.3, "Metal Fatigue Analysis," and/or Section 4.7, "Other Plant Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations, the method used is appropriately defined and discussed in the applicable TLAAs.

[3.5.1-053] - There are no TLAAs associated with component support members, anchor bolts, and welds for Groups B1.1 and B1.2 component supports. Group B1.3 component supports are associated with BWRs; therefore, not applicable.

3.5.2.2.2.6 Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation

Reduction of strength, loss of mechanical properties, and cracking due to irradiation could occur in PWR and BWR Group 4 concrete structures that are exposed to high levels of neutron and gamma radiation. These structures include the reactor (primary/biological) shield wall, the sacrificial shield wall, and the reactor vessel support/pedestal structure. Data related to the effects and significance of neutron and gamma radiation on concrete mechanical and physical properties is limited, especially for conditions (dose, temperature, etc.) representative of light water reactor (LWR) plants. However, based on literature review of existing research, radiation fluence limits of 1 x 10^{19} neutrons/cm^2 neutron radiation and 1 x 10^8 Gy (1 x 10^{10} rad) gamma dose are considered conservative radiation exposure levels beyond which concrete material properties may begin to degrade markedly (Ref. 17, 18, 19).

Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to selected existing AMPs to manage the aging effects of irradiation if the estimated (calculated) fluence levels or irradiation dose received by any portion of the concrete from neutron (fluence cutoff energy E > 0.1 MeV) or gamma radiation exceeds the respective threshold level during the subsequent period of extended operation that could affect intended functions. Higher fluence or dose levels may be allowed in the concrete if tests and/or calculations are provided to evaluate the reduction in strength and/or loss of mechanical properties of concrete from those fluence levels, at or above the operating temperature experienced by the concrete, and the effects are applied to the design calculations. Supporting calculations/analyses, test data, and other technical basis are provided to estimate and evaluate fluence levels and the plant-specific program. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP SLR).

The following information describes the general configuration of the primary shield wall (PSW), secondary shield wall (SSW), and reactor vessel (RV) steel supports, the analytical methods used to determine the neutron and gamma radiation environment and the analytical results of the radiation impact to the primary shield wall, secondary shield wall, and RV steel supports.

<u>Reactor Vessel Steel Supports, Primary Shield Wall, and Secondary Shield Wall Configuration</u>

The RV support structure (short-columns) consists of a support shoe attached to the top of a plate fabricated steel box structure. There are six of these structures supporting three inlet and three outlet nozzles. The box structures are grouted into the surrounding PSW concrete along with anchor bolts (seven per support box). Each vessel support bears on a support shoe, which is fastened to the support structure. The support shoe is a structural member that transmits the support loads to the supporting structure. It is designed to restrain vertical, lateral, and rotational movement of the RV but to allow for thermal growth by permitting radial sliding on the bearing plates at each support.

The PSW is a reinforced concrete wall surrounding and supporting the RV. The inside of the PSW is approximately circular throughout its height. The outside is circular from the structural foundation mat to the top of the basement slab where it becomes polygonal to accommodate surrounding structures, such as secondary shield walls, fuel transfer canal slab, and fuel canal walls.

The PSW has an inside diameter of approximately 16 feet. The PSW extends from below the floor at the 412 feet elevation to an elevation of approximately 437 feet. The lower portion of the PSW, below the base slab (elevation 412 feet) is a 4-foot-thick cylindrical section surrounded by structural foundation mat concrete. The inside face above the haunch area of the wall has a steel liner in and around the neutron detector boxes for the full circumference. This steel liner is not credited for structural function in the analysis of record. The top of the PSW, which is part of the refueling cavity area, is covered by a stainless-steel liner plate; stainless-steel covers are provided over the baffle openings during refueling. The refueling cavity walls extend above the PSW from approximately 437 feet up to the operating floor (elevation 463 feet). The PSW is supported from the Reactor Building foundation mat and encloses the baffle assemblies, reactor coolant penetrations, and neutron detector boxes. The PSW is bounded by the foundation mat, the secondary shield wall compartments and a refueling ring seal at elevation 437 feet 2 ¾ inches which forms the bottom of the refueling cavity. The PSW also supports secondary shield walls forming the refueling canal above elevation 437 feet 2 ¾ inches and associated floor slabs and equipment. The arrangement of the Reactor Building internal concrete is shown in Figure 3.5.2.2.2.6-1.

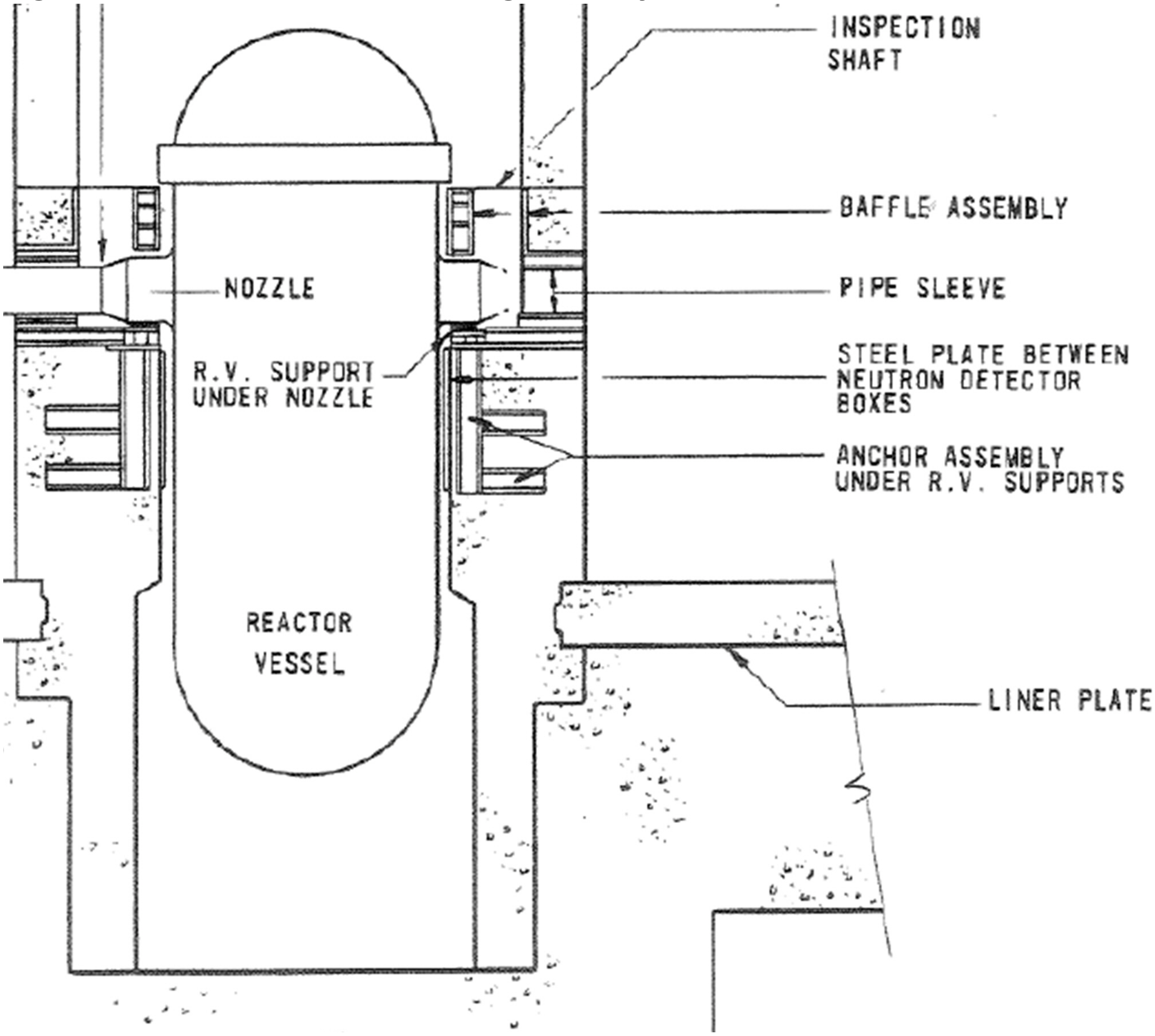
The walls are required to resist normal operating and accident load conditions and require provisions to seal against water entering below the seal ring around the RV and through the top of the baffle openings during refueling operations. The walls are also required as a biological shield to surrounding compartment areas and to support the RV, associated Reactor Coolant pipe rupture penetrations, and the baffle system.

The secondary shield wall forms three compartments located adjacent to and connected with the PSW. These compartments form enclosures for the reactor coolant system equipment and provide biological shielding.

Primary Shield Wall Evaluation

Two analytical models investigate the potential impact of neutron and gamma radiation to the PSW. The first model, developed by Westinghouse, was used to assess the neutron and gamma radiation within the PSW. The second model, developed by the Electric Power Research Institute (EPRI) and described in EPRI Report 3002008129 was used to assess gamma heating of the PSW.

Figure 3.5.2.2.2.6-1 Section through Primary Shield Wall



Neutron fluence and gamma dose calculations were performed to determine exposures to the PSW and RV supports with the plant-specific model. The methodology for the calculations followed the guidance of Regulatory Guide 1.190 and was consistent with the NRC approved methodology described in WCAP-18124-NP-A. The discrete ordinates radiation transport calculations were performed on a fuel cycle-specific basis to determine the neutron and gamma environment within the reactor, cavity, and PSW geometry.

The transport calculations were performed using the two-dimensional discrete ordinates code, RAPTOR-M3G, and the BUGLE-96 cross-section library. Fast neutron (E > 0.1 MeV) fluences and gamma doses tend to decrease with distance as neutrons and gammas travel away from the core. Since the SSW is external to the PSW, the neutron fluence and gamma dose of the SSW is not included in the reactor model and is bounded by the neutron fluence and gamma dose in the PSW.

Westinghouse calculated the maximum neutron fluence (E > 0.1 MeV) and displacements per iron atom (dpa) for the end of the subsequent period of extended operation on the PSW and RV support components. In addition, gamma dose is calculated for the PSW. These calculations were performed on a cycle-specific basis for cycles 1-27. Projections beyond cycle 27 were based on the average core power distributions and reactor operating conditions of cycles 25-27 but included a +10% bias on the peripheral and re-entrant corner assembly relative powers. Peripheral assemblies have one or more faces exposed to the core baffle plates and re-entrant corner assemblies have one corner exposed to the core baffle plates. Fluence and gamma dose exposures for the PSW are presented in Table 3.5.2.2.2.6-1 below.

Table 3.5.2.2.2.6-1 Maximum End of Subsequent Period of Extended Operation Exposures for Concrete (72 EFPY)

Component	Neutron Fluence (n/cm^2)	Gamma Dose (Gy)
PSW	5.02 x 10^{19}	1.90 x 10^8
NUREG-2192 Threshold	1.00 x 10^{19}	1.00 x 10^8

The values for fluence and gamma dose projections for the PSW are greater than the threshold limits of NUREG-2192. As a result, the PSW was evaluated for irradiation effects to ensure it will maintain its structural integrity and perform its current licensing basis (CLB) listed design functions.

Neutron and Gamma Attenuation in the PSW

Neutron fluence attenuation and gamma dose attenuation were determined using RAPTOR-M3G, and radiological effects on the PSW were determined utilizing industry guidance provided in EPRI report 3002018400, “2020 Update to Irradiation of Concrete Guidance: Basis for Evaluation of Concrete Biological Shield Wall for Aging Management”. The fluence and gamma results have been adjusted to account for uncertainty (20% increase). The results are presented as a function of the radial depth beyond the inside surface of the PSW. However, the geometry of the PSW is complicated by the shape of the ex-core detector wells. As a result, the results at certain azimuths reported at a given depth into concrete actually represent a location on the side of the ex-core detector wells, very close to the concrete surface. The results are therefore carefully studied and screened to filter results which are indicative of local exceedances along the detector walls, which do not have any bearing on the structural capabilities of the PSW. The structural function of these detector walls is still met. After post-processing, the neutron fluence is found to exceed the threshold (1.00 x 10^{19} neutrons / cm^2) only to a depth into the concrete of less than 4 inches. The gamma dose is found to exceed the threshold (1.00 x 10^8 Gy) only to a depth into the concrete of less than 10 inches.

To account for the effects of neutron fluence, including radiation induced volumetric expansion (RIVE), the region where neutron fluence is exceeded in the concrete is completely neglected and is assumed to contribute zero strength to the PSW. To account for the effects of gamma dose, the region of gamma dose exceedance (beyond 4 inches, where concrete strength is taken as zero due to neutron fluence) is assumed to have 90% of its nominal compressive strength based on Figure 3-4 of EPRI 3002018400.

The primary vertical, hoop, and shear reinforcement which is considered in the analysis of record is located outside the zones of neutron and gamma threshold exceedances. Therefore, there is no reduction in the ability of the primary reinforcement to carry load, and no reduction in PSW capacity as a result of rebar capacity reduction.

Further, because the liner plate is not relied on for any structural function, the assumption of the concrete immediately inside the liner having zero strength does not have any negative impact on liner function. Even if the liner were to experience minor distortion, due to swelling or crushing of concrete inside the liner, there would not be an impact to the PSW structural capacity or function.

The maximum aggregate swelling strains caused by RIVE have been tabulated at various depths into the PSW and compared to the concrete ultimate compressive strain. The results do not indicate any potential for cracking beyond the interior 4 inches of the PSW, which is already conservatively assumed to have zero strength. Therefore, the effect of RIVE-induced cracking is accounted for and bounded by the conservative assumptions made in the analysis.

The concrete strength is 0% for the first 4 inches due to neutron fluence, and 90% for an additional 6 inches to account for gamma effects, which is conservative considering the reduction of 10% in concrete strength would be at the surface of the PSW, with full concrete strength available at 10 inches.

Regarding the effects on the liner plate, the maximum RIVE effect zone of 4 inches is applicable only to a limited number of anchors around the mid-height of the active fuel, which are conservatively assumed ineffective. The rest of the anchors remain effective. The overall integrity of the PSW liner is not adversely affected by RIVE effects.

The liner plate is attached to the wall via ½” x 5 5/16” headed concrete anchors, field welded at 12” to 18” on center. Should any concrete damage occur at the affected elevations, the anchors outside of the radiation-affected region would remain positively attached and fully effective. Additionally, the heads of anchors, even at elevations which exceed the thresholds, are located in the sound unaffected concrete. Consequently, the liner is constrained globally to the wall and any distortion would be limited. The steel liner plate has sufficient ductility and toughness to prevent local rupture. Additionally, the maximum fluence at 72 EFPY on the liner plate, adjusted to add 20% for analytical uncertainty, is 4.55×10^{18} n/cm^2 (E > 1.0 MeV). This is less than the damage threshold for the steel of 1×10^{19} n/cm^2 (E > 1.0 MeV). Therefore, should any concrete damage occur (e.g., localized crushing of inner surface of PSW), the liner plate would confine and retain the damaged concrete in place, preventing the generation of loose objects or interfering with operational function.

The effect these degraded properties have on the PSW structural capacity is quantified and compared to the current analysis of record capacity. The quantification is performed through consideration of the axial plus bending moment capacity of the PSW, in accordance with the assumptions and methods identified in the design code of record. The reduced PSW capacity is taken in consideration with the current analysis of record demand to capacity ratios. A summary of results for the vertical and hoop directions (considering both reinforcement ratios at the inside and outside of the PSW), as well as shear capacity, is provided in Table 3.5.2.2.2.6-2 below

Table 3.5.2.2.2.6-2 Summary of SLR Demand to Capacity Ratios for PSW Concrete

		Vertical		Hoop		Shear
		In	Out	In	Out	
Analysis of Record	Demand / Capacity Ratio	0.53	0.59	0.65	0.86	0.54
Subsequent License Renewal	Fraction of the Total AOR Capacity Remaining after 72 EFPY	0.83	0.83	0.91	0.91	0.95
	Updated SLR Demand / Capacity Ratio[a]	**0.64**	**0.71**	**0.71**	**0.95**	**0.57**

Footnote(s):
(a) A ratio of less than 1.00 is acceptable.

Comparing with the un-irradiated concrete (where the maximum interaction ratio (IR) was calculated as 0.86), the maximum IR for the irradiated concrete was determined to be 0.95 which has been increased but remains less than 1.0. The maximum IR of 0.95 occurs in an accident load combination, which includes accident temperatures and pressures.

In addition to the conservatism of assuming zero strength for the entire neutron fluence affected zone, another significant conservatism is that the IR above does not include any reduction in PSW demand to account for leak-before-break (LBB) implementation, which significantly reduces the PSW load demand in the region of interest. VCSNS has undergone LBB evaluation and has received approval to eliminate dynamic effects associated with postulated large pipe breaks from its design basis.

The estimated PSW load demand as a result of LBB implementation, as a percentage of AOR demand, is 32% for maximum vertical load and 56% for maximum horizontal load. In the zone of potential radiation damage, the PSW demand is almost wholly dictated by the RV support load in this region.

The PSW contains embedded RV support anchorages. The maximum fluence at 72 EFPY on the RV support anchorage embedded steel (within the PSW), adjusted to add 20% for analytical uncertainty, is 8.82×10^{17} n/cm^2 (E > 1.0 MeV). This is less than the damage threshold for the steel of 1.00×10^{19} n/cm^2 (E > 1.0 MeV), per EPRI Report 3002013084.

The conservatisms in the evaluation were as follows:

- Exposures were based on 72 EFPY
- Future projections included a 10% positive bias on the peripheral and re-entrant corner assemblies on the projection fuel cycle.
- The loss of strength in the PSW concrete as a result of gamma dose incident on the PSW was assumed to apply to the full thickness to the point where the gamma dose falls below the NUREG-2192 damage threshold, when in reality the gamma dose effect would reduce in an approximately linear fashion from the outside surface.
- The latest research data presented in EPRI Report 3002011710 indicated that the threshold for damage to concrete from gamma dose may be higher than 1×10^8 Gy.
- The IR does not include any reduction in PSW demand to account for LBB implementation.
- Reduction in LOCA loads from LBB evaluation not taken into account.

As evidenced by the evaluation described above, and considering the integrated effects of neutron fluence, gamma dose, and gamma heating, the PSW is capable of carrying the loads of the RV at the end of 80 years of plant operation. Therefore, the PSW will continue to satisfy its design criteria considering the long-term radiation effects and a plant specific AMP or enhancements to an existing AMP is not required.

Gamma Heating

The impact of gamma heating on the PSW has been evaluated and it was concluded that the maximum PSW concrete temperature would be less than 128°F. This temperature is bounded by the long-term PSW concrete temperature limit of 150°F reported in Section 3.8.1.5.1.2 of the FSAR. Therefore, gamma heating is not an issue for the PSW concrete.

Secondary Shield Wall Evaluation

The neutron fluence and gamma dose threshold limits of NUREG-2192 are not exceeded beyond the first 10 inches of the PSW. The SSW is physically external to the PSW. The entire SSW is further from the core at all points compared to the PSW, meaning that the neutron fluence and gamma dose is higher in the PSW than the SSW. Therefore, since the NUREG-2192 threshold limits are not exceeded external to the PSW and the SSW is physically external to the PSW, the neutron and gamma dose limits in the SSW are lower than the NUREG-2192 threshold limits. Since the NUREG-2192 threshold limits are not exceeded in the SSW, separate analysis of the SSW is not required.

Reactor Vessel Steel Support Evaluation

The NRC previously identified radiation embrittlement of the RV supports as a generic safety issue (GSI-15). The NRC resolved the issue, as documented in NUREG-1509 on the basis of a risk-informed evaluation, without imposing new requirements on licensees. The review concluded that loss of fracture toughness due to irradiation embrittlement will not affect the ability of the RV structural steel to perform its component intended functions through the original design life of the plant. However, this review was not performed for an 80-year plant life. Accordingly, a review of the aging effect of reduction in fracture toughness due to embrittlement from exposure to neutron fluence of the RV support steel was performed for subsequent license renewal in WCAP-18785-NP.

NUREG-1509, “Radiation Effects on Reactor Pressure Vessel Supports,” provides a screening evaluation approach to evaluate the loss of fracture toughness of RV supports due to radiation effects for long term operation. The screening evaluation includes the following criteria for assessing the structural integrity of the RV steel supports:

- The initial nil ductility temperature (NDT) of the RV supports is well below the minimum operating temperature.
- The radiation exposure at the supports is low.
- The peak tensile stresses are 6 ksi or less.

The RV steel supports were compared to the screening criteria in NUREG-1509 to assess the structural integrity. The two screening criteria for radiation exposure and peak tensile stresses (i.e., below 6 ksi or less) were not met as described below.

Radiation Exposure

The RV supports are located near the RV active core and subjected to high neutron irradiation. Based upon this consideration, the screening criterion of low radiation exposure at the RV steel supports are conservatively considered as not satisfied.

As previously discussed, neutron fluence calculations were performed by Westinghouse to determine exposures to the RV supports. The methodology for the calculations followed the guidance of Regulatory Guide 1.190 and was consistent with the NRC approved methodology described in WCAP-18124-NP-A. This methodology has been generically approved for calculations of exposure of the RV beltline (generally, RV materials opposite the active fuel). No method, generic or specific to VCSNS has been approved by the NRC for the other calculations performed (i.e., exposure of RV extended beltline materials, RV supports, and PSW concrete).

Westinghouse calculated the maximum neutron embrittlement (in terms of displacements per iron atom (dpa)) for 72 EFPY on the RV support components, based on the reactor models and radiation transport calculations performed for the SLR RV neutron exposure. These calculations were performed on a cycle-specific basis for cycles 1-27. Projections beyond cycle 27 were based on the average core power distributions and reactor operating conditions of cycles 25-27 but included a +10% bias on the peripheral and re-entrant corner assembly relative powers. The iron dpa values were increased 25% to represent analytical uncertainties associated with the methodology used to calculate the iron dpa values.

Maximum projected neutron exposures (E > 0.1 MeV) in terms of displacements per iron atom of the RV support structures are provided in Table 3.5.2.2.2.6-3 below.

Table 3.5.2.2.2.6-3 Iron Displacement per Atom at the RV Support Structure (with Analytical Uncertainties) for 72 EFPY

	Iron Displacement per Atom (dpa)[(a)] +10% bias on the peripheral and re-entrant corner assembly relative powers +25% for uncertainties			
Component	Support Box Plate	Support Box	Support Shoe	Support Box Plate Bolt
Iron dpa	4.14E-03	3.78E-03	2.24E-03	7.44E-05

Footnote(s):
(a) Iron dpa values were calculated for energy levels above and below 0.1 MeV (i.e., all energy levels).

<u>Peak Tensile Stress</u>

The peak tensile stresses due to deadweight, thermal, seismic, and LOCA loads were determined at various locations throughout the RV support, including support box plates, support shoe, anchor bolts and hold down/guide pins. These components have tensile stress larger than 6 ksi; thus, the screening criterion of peak tensile stresses of 6 ksi or less is not satisfied.

In addition to the screening criteria, NUREG-1509 also provides an option to evaluate the loss of fracture toughness of RV steel supports using a fracture mechanics evaluation. A fracture mechanics evaluation consistent with the methodology provided in NUREG-1509 was utilized in the evaluation of the RV steel supports as discussed below.

<u>Fracture Mechanics Evaluation</u>

The goal of the fracture mechanics evaluation was to demonstrate that brittle fracture is not a concern for the RV structural steels based on 80 years (72 EFPY) of neutron embrittlement. Linear elastic fracture mechanics (LEFM) was used as a conservative methodology to evaluate the structural integrity of the supports. The LEFM methodology is illustrated in a flowchart format (see Figure 2-1 of WCAP-18785-NP) based on the guidance provided in NUREG-1509 for a fracture mechanics approach to account for radiation effects on RV support steels. The LEFM methodology is briefly described in the following paragraphs.

The LEFM evaluation is completed by calculating either 1) critical stresses and comparing to actual stress, or 2) critical flaw length and comparing to allowable flaw length, depending on the analyzed component. The critical stress method is completed for the plate components (top plate, vertical plates, and bottom plates) and the support shoe, while the critical flaw length method is completed for the bar components (anchor bolts and hold down/guide pins). For both methods, the critical stress or critical flaw length was determined by equating the stress intensity factor to fracture toughness.

The fracture toughness used for each of the components are as follows: the plate components are conservatively based on the ASME Code, Section XI lower bound K_{Ic} fracture toughness of 33.2 ksi√in, the anchor bolts are conservatively based on the 95% lower tolerance bound Master Curve K_{Jc} fracture toughness of 22.9 ksi√in, the support shoe is based on a material-specific fracture toughness of 55 ksi√in for 72 EFPY, and the hold down/guide pins are based on a material-specific fracture toughness of 42 ksi√in for 72 EFPY.

The stress intensity factors determined for the plate components and the support shoe are based on a semi-elliptical postulated flaw. The stress intensity factors determined for the bar components (i.e., anchor bolts and hold down/guide pins) are based on a postulated 360° continuous circumferential flaw, straight front flaw, and semi-circular front flaw in a bar model.

The loading combinations (normal, upset, and faulted) for the RV supports are consistent with the analysis of record, and are used to calculate stresses for each component. Consideration of all applicable loading conditions, such as deadweight, seismic, loss-of-coolant accident, welding residual stresses (where applicable), and thermal stresses are accounted for in the analysis.

The results of the LEFM analyses for the RV support components at the end of 80 years (72 EFPY) are presented in Table 3.5.2.2.2.6-4 and Table 3.5.2.2.2.6-5.

Table 3.5.2.2.2.6-4 Summary of RV Support Critical Stress

	Component [(a)]			
	Top Plate [(b)]	Vertical Plate [(b)]	Bottom Plate [(b)]	Support Shoe
Critical Stress (ksi) for 72 EFPY	39.8	54.5	44.8	79.0

Footnote(s):

(a) The critical stresses are determined by setting stress intensity factor equal to fracture toughness and back-calculating stress. The calculated critical stresses are compared to the actual stresses. The critical stresses are larger than the actual stresses; thereby concluding that the RV support components continue to be structurally stable (i.e., flaw tolerant) considering 80 years of radiation or embrittlement effects on the supports.

(b) This location considers welding residual stress.

Table 3.5.2.2.2.6-5 Summary of RV Support Critical Flaw Length

Loading Condition	Critical Flaw Length (in.) [(a)]	
	Anchor Bolts	Hold Down/Guide Pins
Normal	2.43	3.65
Upset	See Footnote (b)	3.87
Faulted-1		1.46 [(c)]
Faulted-2		3.72

Footnote(s):

(a) The critical flaw lengths are determined by setting stress intensity factor equal to fracture toughness and back-calculating flaw length. The critical flaw lengths provided are the lengths around the circumference of the bar component. There are no significant transients or thermal cycling that would cause any crack growth over time. The critical flaw lengths are compared against the Section XI allowable flaw lengths (permissible per Section 4.3.4.1 of NUREG-1509). The critical flaw lengths are larger than the ASME Code, Section XI allowable flaw lengths; thereby concluding that the RV support components continue to be structurally stable (i.e., flaw tolerant) considering 80 years of radiation or embrittlement effects on the supports.

(b) Only the friction load during the Normal operation condition on the anchor bolt is considered. The Upset and Faulted conditions are not applicable for this component. Therefore, only the Normal loading condition critical flaw lengths are provided.

(c) The critical flaw length for the postulated semi-circular front is provided since the straight front flaw stress intensity factor limits of applicability are exceeded.

As discussed in Table 3.5.2.2.2.6-4, the support box plates and support shoe actual stresses are less than the critical stresses. As discussed in Table 3.5.2.2.2.6-5, the anchor bolts and hold down/guide pins critical flaw lengths are larger than the Section XI allowable flaw lengths.

The change in embrittlement from 42 EFPY to 72 EFPY for the support shoe and hold down/guide pins were considered to evaluate the change of radiation embrittlement with time. For the support plates and anchor bolts, the fracture mechanics analysis conservatively considers lower bound fracture toughness, which represents infinite embrittlement. Thus, only the support shoe and hold down/guide pins component specific fracture toughness was considered in the change of embrittlement evaluation. The evaluation demonstrates that the supports have sufficient flaw tolerance to not be impacted by neutron embrittlement from the original design life of 40 years to the SLR period of 80 years (see Section 8.2 of WCAP-18785-NP for additional discussion).

Based on these conclusions, the RV supports continue to be structurally stable (i.e., flaw tolerant) considering 80 years of radiation embrittlement effects on the supports. Additionally, no additional inspections or enhancements are required for aging management of the RV supports, and the current ASME Code, Section XI inspection requirements are sufficient. Furthermore, the loads from the RV are transmitted to the PSW, and the PSW can accommodate the operating and design basis loads. Thus, the RV will continue to be adequately supported for 80 years of plant operation.

Operating Experience

Per Section 4.3.1 of NUREG-1509, physical examination of the structural components is essential to the re-evaluation completed herein and an assessment of the overall condition of the RV support structure. Based on the RV support equipment specification, the structural steel components and welds had required examination per ASME Code, Section III, Appendix IX (radiography, liquid penetrant, magnetic particle, and ultrasonic testing). During initial fabrication, any unsatisfactory conditions were to be removed, re-welded, and re-examined. Thus, it is expected that the analyzed components are free from cracks after initial fabrication and after an extended period of time since crack growth mechanism are not present at the RV supports. The most recent RV support inspections were performed per ASME Code, Section XI, IWF guidance. During the inspections, evidence of dry boron residue was discovered based on remote visual inspection of the RV supports. The boric acid deposits were dry and crystalline with no visual evidence of active leakage. This leakage was considered historical, as there is no active leakage from either the RCS pressure boundary or the refueling cavity. It was concluded that the visual inspection identified no indications, no significant surface degradations nor component damage on the RV support, and that no evidence appears rejectable per ASME Code, Section XI, IWF-3410. The RV supports are within the ASME Code, Section XI, ISI program and any further leaks and conditions that would affect the supports will be identified and periodically monitored.

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Results Tables: Containment, Structures and Component Supports

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-001	Concrete: dome; wall; basemat; ring girders; buttresses, concrete elements, all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	Yes (SRP-SLR Section 3.5.2.2.1.1)	Not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.1.1.
3.5.1-002	Concrete: foundation; subfoundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	AMP XI.S6, Structures Monitoring	Yes (SRP-SLR Section 3.5.2.2.1.1)	Not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.1.1.
3.5.1-003	Concrete: dome; wall; basemat; ring girders; buttresses, concrete: containment; wall; basemat, concrete: basemat, concrete fill-in annulus	Reduction of strength and modulus of elasticity due to elevated temperature (>150°F general; >200°F local)	Plant-specific aging management program, or AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.2)	Not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.1.2.
3.5.1-004	Steel elements (inaccessible areas): drywell shell; drywell head	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Not applicable - BWR only.
3.5.1-005	Steel elements (inaccessible areas): liner; liner anchors; integral attachments, steel elements (inaccessible areas): suppression chamber; drywell; drywell head; embedded shell; region shielded by diaphragm floor (as applicable)	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Consistent with NUREG-2191. See further evaluation in Section 3.5.2.2.1.3.1.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-006	Steel elements: torus shell	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.3.2)	Not applicable - BWR only.
3.5.1-007	Steel elements: torus ring girders; downcomers;, Steel elements: suppression chamber shell (interior surface)	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE	Yes (SRP-SLR Section 3.5.2.2.1.3.3)	Not applicable - BWR only.
3.5.1-008	Prestressing system: tendons	Loss of prestress due to relaxation; shrinkage; creep; elevated temperature	TLAA, SRP-SLR Section 4.5, Concrete Containment Tendon Prestress, and/or SRP-SLR Section 4.7, Other Plant-Specific Time-Limited Aging Analyses	Yes (SRP-SLR Section 3.5.2.2.1.4)	Consistent with NUREG-2191. See further evaluation in Section 3.5.2.2.1.4.
3.5.1-009	Metal liner, metal plate, personnel airlock, equipment hatch, CRD hatch, penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell; unbraced downcomers, steel elements: vent header; downcomers	Cumulative fatigue damage due to cyclic loading (Only if CLB fatigue analysis exists)	TLAA, SRP-SLR Section 4.6, Containment Liner Plate and Penetration Fatigue Analysis	Yes (SRP-SLR Section 3.5.2.2.1.5)	Consistent with NUREG-2191. See further evaluation in Section 3.5.2.2.1.5.
3.5.1-010	Penetration sleeves; penetration bellows	Cracking due to SCC	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.6)	Consistent with NUREG-2191. In addition to Reactor Building, components in Auxiliary Systems (fuel handling) and the Auxiliary Building are aligned to this row. See further evaluation in Section 3.5.2.2.1.6.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-011	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program, or AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.7)	Consistent with NUREG-2191. Loss of material (spalling, scaling) and cracking of concrete elements (inaccessible areas) are managed by the ASME Section XI, Subsection IWL (B2.1.31) program and Structures Monitoring (B2.1.35) program. See further evaluation in Section 3.5.2.2.1.7.
3.5.1-012	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment, concrete fill-in annulus	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program, or AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.8)	Consistent with NUREG-2191. Cracking of concrete elements (inaccessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.31) program and Structures Monitoring (B2.1.35) program. See further evaluation in Section 3.5.2.2.1.8.
3.5.1-014	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program, or AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.9)	Consistent with NUREG-2191. Increase in porosity and permeability; loss of strength of concrete elements (inaccessible areas) are managed by the ASME Section XI, Subsection IWL (B2.1.31) program and Structures Monitoring (B2.1.35) program. See further evaluation in Section 3.5.2.2.1.9.
3.5.1-016	Concrete (accessible areas): basemat, concrete: containment; wall	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Increase in porosity and permeability; cracking; loss of material (spalling, scaling) of Reactor Building concrete elements (accessible areas) are managed by the ASME Section XI, Subsection IWL (B2.1.31) program.
3.5.1-018	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Loss of material (spalling, scaling) and cracking of Reactor Building concrete elements (accessible areas) are managed by the ASME Section XI, Subsection IWL (B2.1.31) program.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-019	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, containment; concrete fill-in annulus	Cracking due to expansion from reaction with aggregates	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Cracking of Reactor Building concrete elements (accessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.31) program.
3.5.1-020	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S2, ASME Section XI, Subsection IWL	No	Consistent with NUREG-2191.
3.5.1-021	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Cracking; loss of bond; and loss of material (spalling, scaling) of Reactor Building concrete elements (accessible areas) are managed by the ASME Section XI, Subsection IWL (B2.1.31) program.
3.5.1-023	Concrete (inaccessible areas): basemat; reinforcing steel, dome; wall	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Cracking; loss of bond; and loss of material (spalling, scaling) of Reactor Building concrete elements (inaccessible areas) are managed by the ASME Section XI, Subsection IWL (B2.1.31) program and Structures Monitoring (B2.1.35) program.
3.5.1-024	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): dome; wall; basemat	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Increase in porosity and permeability; cracking; loss of material (spalling, scaling) of Reactor Building concrete elements (inaccessible areas), and Reactor Building concrete elements (accessible areas) are managed by the ASME Section XI, Subsection IWL (B2.1.31) program and Structures Monitoring (B2.1.35) program.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-026	Moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S1, ASME Section XI, Subsection IWE	No	Consistent with NUREG-2191.
3.5.1-027	Metal liner, metal plate, airlock, equipment hatch, CRD hatch; penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.5)	Consistent with NUREG-2191. In addition to Reactor Building, components in Auxiliary Building are aligned to this row. See further evaluation in Section 3.5.2.2.1.5.
3.5.1-028	Personnel airlock, equipment hatch, CRD hatch	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	No	Consistent with NUREG-2191. In addition, components in Auxiliary Systems (fuel handling) are aligned to this row.
3.5.1-029	Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms	Loss of leak tightness due to mechanical wear	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	No	Consistent with NUREG-2191.
3.5.1-030	Pressure-retaining bolting	Loss of preload due to self-loosening	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	No	Consistent with NUREG-2191.
3.5.1-031	Pressure-retaining bolting, steel elements: downcomer pipes	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE	No	Consistent with NUREG-2191.
3.5.1-032	Prestressing system: tendons; anchorage components	Loss of material due to corrosion	AMP XI.S2, ASME Section XI, Subsection IWL	No	Consistent with NUREG-2191.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-033	Seals and gaskets	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S4, 10 CFR Part 50, Appendix J	No	Consistent with NUREG-2191.
3.5.1-034	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, Protective Coating Monitoring and Maintenance	No	Consistent with NUREG-2191.
3.5.1-035	Steel elements (accessible areas): liner; liner anchors; integral attachments, penetration sleeves, drywell shell; drywell head; drywell shell in sand pocket regions; suppression chamber; drywell; embedded shell; region shielded by diaphragm floor (as applicable)	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Consistent with NUREG-2191. In addition to Reactor Building, components in Auxiliary Building are aligned to this row. See further evaluation in Section 3.5.2.2.1.3.1.
3.5.1-036	Steel elements: drywell head; downcomers	Loss of material due to mechanical wear, including fretting	AMP XI.S1, ASME Section XI, Subsection IWE	No	Not applicable - BWR only.
3.5.1-037	Steel elements: suppression chamber (torus) liner (interior surface)	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	No	Not applicable - BWR only.
3.5.1-038	Steel elements: suppression chamber shell (interior surface)	Cracking due to SCC	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.6)	Not applicable - BWR only.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-039	Steel elements: vent line bellows	Cracking due to SCC	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.6)	Not applicable - BWR only.
3.5.1-040	Unbraced downcomers, steel elements: vent header; downcomers	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	AMP XI.S1, ASME Section XI, Subsection IWE	Yes (SRP-SLR Section 3.5.2.2.1.5)	Not applicable - BWR only.
3.5.1-041	Steel elements: drywell support skirt, steel elements (inaccessible areas): support skirt	None	None	No	Not applicable - BWR only.
3.5.1-042	Groups 1-3, 5, 7- 9: concrete (inaccessible areas): foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.1)	Consistent with NUREG-2191. Loss of material (spalling, scaling) and cracking of Groups 1-3, 5, 7- 9: concrete elements (inaccessible areas) is managed by the Structures Monitoring (B2.1.35) program. See further evaluation in Section 3.5.2.2.2.1.1.
3.5.1-043	All Groups except Group 6: concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.2)	Consistent with NUREG-2191. Cracking of all Groups except Group 6: concrete elements (inaccessible areas) is managed by the Structures Monitoring (B2.1.35) program. See further evaluation in Section 3.5.2.2.2.1.2.
3.5.1-044	All Groups: concrete: all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S6, Structures Monitoring	Yes (SRP-SLR Section 3.5.2.2.2.1.3)	Consistent with NUREG-2191. See further evaluation in Section 3.5.2.2.2.1.3.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-046	Groups 1-3, 5-9: concrete: foundation; subfoundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	AMP XI.S6, Structures Monitoring	Yes (SRP-SLR Section 3.5.2.2.2.1.3)	Consistent with NUREG-2191 for differential settlement, not applicable for erosion of porous concrete. See further evaluation in Section 3.5.2.2.2.1.3.
3.5.1-047	Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below-grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.4)	Consistent with NUREG-2191. Increase in porosity and permeability; loss of strength of Groups 1-5, 7-9: concrete elements (inaccessible areas) is managed by the Structures Monitoring (B2.1.35) program. See further evaluation in Section 3.5.2.2.2.1.4.
3.5.1-048	Groups 1-5: concrete: all	Reduction of strength and modulus due to elevated temperature (>150°F general; >200°F local)	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.2)	Not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.2.2.
3.5.1-049	Groups 6 - concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.1)	Consistent with NUREG-2191. Loss of material (spalling, scaling) and cracking of Group 6 - concrete elements (inaccessible areas) is managed by the Structures Monitoring (B2.1.35) program. See further evaluation in Section 3.5.2.2.2.3.1.
3.5.1-050	Groups 6: concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.2)	Consistent with NUREG-2191. Cracking of Group 6: concrete elements (inaccessible areas) is managed by the Structures Monitoring (B2.1.35) program. See further evaluation in Section 3.5.2.2.2.3.2.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-051	Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.3)	Consistent with NUREG-2191. Increase in porosity and permeability; loss of strength of Group 6: concrete elements (inaccessible areas) is managed by the Structures Monitoring (B2.1.35) program. See further evaluation in Section 3.5.2.2.2.3.3.
3.5.1-052	Groups 7, 8 - steel components: tank liner	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	Plant-specific aging management program	Yes (SRP-SLR Section 3.5.2.2.2.4)	Consistent with NUREG-2191. The plant specific aging management program used to manage cracking and loss of material is the ASME Section XI, Subsection IWE (B2.1.30) program. See further evaluation in Section 3.5.2.2.2.4.
3.5.1-053	Support members; welds; bolted connections; support anchorage to building structure	Cumulative fatigue damage due to cyclic loading (Only if CLB fatigue analysis exists)	TLAA, SRP-SLR Section 4.3 Metal Fatigue, and/or Section 4.7 Other Plant-Specific Time-Limited Aging Analyses	Yes (SRP-SLR Section 3.5.2.2.2.5)	Not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.2.5.
3.5.1-054	All groups except 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-055	Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-056	Concrete: exterior above- and below- grade; foundation; interior slab	Loss of material due to abrasion; cavitation	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. Loss of material of concrete elements is managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program. However, concrete elements for the Circulating Water Intake Structure, the aging management program used to manage loss of material is the Structures Monitoring (B2.1.35) program.
3.5.1-057	Constant and variable load spring hangers; guides; stops	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S3, ASME Section XI, Subsection IWF	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWF (B2.1.32) program implementation. Additionally, supports for non-ASME Code piping systems and components, the aging management program used to manage the loss of mechanical function is the Structures Monitoring (B2.1.35) program.
3.5.1-058	Earthen water-control structures: dams; embankments; reservoirs; channels; canals and ponds	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. Loss of material; loss of form of earthen water-control structures are managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program.
3.5.1-059	Group 6: concrete (accessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. Cracking; loss of bond; and loss of material (spalling, scaling) of Group 6: concrete elements (accessible areas) are managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-060	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. Loss of material (spalling, scaling) and cracking of Group 6: concrete elements (accessible areas) are managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program.
3.5.1-061	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. Increase in porosity and permeability; loss of strength of Group 6: concrete elements (accessible areas) are managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program.
3.5.1-062	Group 6: Wooden Piles; sheeting	Loss of material; change in material properties due to weathering, chemical degradation, and insect infestation repeated wetting and drying, fungal decay	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Not applicable. There are no in-scope Group 6: Wooden Piles; sheeting in the Containments, Structures, and Component Supports. The associated NUREG-2191 aging items are not used.
3.5.1-063	Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-064	Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-065	Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Groups 1-3, 5, 7-9: concrete (accessible areas): below-grade exterior; foundation, Groups 6: concrete (inaccessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-066	Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-067	Groups 1-5, 7, 9: Concrete: interior; above-grade exterior, Groups 1-3, 5, 7-9 - concrete (inaccessible areas): below-grade exterior; foundation, Group 6: concrete (inaccessible areas): all	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-068	High-strength steel structural bolting	Cracking due to SCC	AMP XI.S3, ASME Section XI, Subsection IWF	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWF (B2.1.32) program implementation.
3.5.1-070	Masonry walls: all	Cracking due to restraint shrinkage, creep, aggressive environment	AMP XI.S5, Masonry Walls	No	Consistent with NUREG-2191.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-071	Masonry walls: all	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S5, Masonry Walls	No	Consistent with NUREG-2191.
3.5.1-072	Seals; gasket; moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Additionally, for the Auxiliary Building and yard structures tank foundations, loss of sealing for caulking and sealants is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.
3.5.1-073	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, Protective Coating Monitoring and Maintenance	No	Consistent with NUREG-2191.
3.5.1-074	Sliding support bearings; sliding support surfaces	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-075	Sliding surfaces	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S3, ASME Section XI, Subsection IWF	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWF (B2.1.32) program implementation.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-076	Sliding surfaces: radial beam seats in BWR drywell	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S6, Structures Monitoring	No	Not applicable - BWR only.
3.5.1-077	Steel components: all structural steel	Loss of material due to corrosion	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-078	Stainless steel fuel pool liner	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	AMP XI.M2, Water Chemistry, and monitoring of the spent fuel pool water level and leakage from the leak chase channels.	No	Consistent with NUREG-2191. Additionally, for the reactor building refueling cavity/fuel transfer canal liner, cracking and loss of material is managed by the Water Chemistry (B2.1.2) program and Structures Monitoring (B2.1.35) program. Monitoring of the spent fuel pool water level and leakage from the leak chase channels is performed by the Structures Monitoring (B2.1.35) program.
3.5.1-079	Steel components: piles	Loss of material due to corrosion	AMP XI.S6, Structures Monitoring	No	Not applicable. There are no in-scope steel components: piles in the Containments, Structures, and Component Supports. The associated NUREG-2191 aging items are not used.
3.5.1-080	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-081	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S3, ASME Section XI, Subsection IWF	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWF (B2.1.32) program implementation.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-082	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, Structures Monitoring	No	Not applicable. Loss of material of structural bolting is addressed in row 3.5.1-080. Galvanized steel structural bolting is evaluated using NUREG-2191 aging items for steel structural bolting. The associated NUREG-2191 aging items are not used.
3.5.1-083	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191, however, a different aging management program is credited for structural bolting located in the Circulating Water Intake Structure. The Structures Monitoring (B2.1.35) program manages loss of material of structural bolting located in the Circulating Water Intake Structure.
3.5.1-085	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.S3, ASME Section XI, Subsection IWF	No	Not applicable. There is no in-scope stainless steel ASME piping and component support structural bolting in a treated water environment in the Containments, Structures, and Component Supports. The associated NUREG-2191 aging items are not used.
3.5.1-086	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.S3, ASME Section XI, Subsection IWF	No	Not applicable. Loss of material of structural bolting is addressed in row 3.5.1-081. Galvanized steel structural bolting is evaluated using NUREG-2191 aging items for steel structural bolting. The associated NUREG-2191 aging items are not used.
3.5.1-087	Structural bolting	Loss of preload due to self-loosening	AMP XI.S3, ASME Section XI, Subsection IWF	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWF (B2.1.32) program implementation.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-088	Structural bolting	Loss of preload due to self-loosening	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191, however, a different aging management program is credited for bolting associated with Auxiliary Systems (materials handling) and the Reactor Building. Loss of preload of bolting in Auxiliary Systems (materials handling) will be managed by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13) program. Loss of preload of Reactor Building stainless steel bolting will be managed by the ASME Section XI, Subsection IWE (B2.1.30) and 10 CFR Part 50, Appendix J (B2.1.33) programs.
3.5.1-089	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to boric acid corrosion	AMP XI.M10, Boric Acid Corrosion	No	Consistent with NUREG-2191.
3.5.1-090	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.S3, ASME Section XI, Subsection IWF	No	Not applicable. There are no in-scope stainless steel ASME piping and component support members; welds; bolted connections; support anchorage to building structure in a treated water environment in the Containments, Structures, and Component Supports. The associated NUREG-2191 aging items are not used.
3.5.1-091	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general, pitting corrosion	AMP XI.S3, ASME Section XI, Subsection IWF	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWF (B2.1.32) program implementation.
3.5.1-092	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general, pitting corrosion	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-093	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting, crevice corrosion	AMP XI.S6, Structures Monitoring	No	Not applicable. Galvanized steel components are evaluated using NUREG-2191 aging items for steel. Loss of material of galvanized steel components is addressed in row 3.5.1-092. The associated NUREG-2191 aging items are not used.
3.5.1-094	Vibration isolation elements	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	AMP XI.S3, ASME Section XI, Subsection IWF, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Reduction or loss of isolation function of vibration isolation elements is managed by the Structures Monitoring (B2.1.35) program.
3.5.1-095	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	None	None	No	Not applicable. Galvanized steel components are evaluated using NUREG-2191 aging items for steel. Refer to row 3.5.1-092. The associated NUREG-2191 aging items are not used.
3.5.1-096	Groups 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants	No	Consistent with NUREG-2191.
3.5.1-097	Group 4: Concrete (reactor cavity area proximate to the reactor vessel): reactor (primary/biological) shield wall; sacrificial shield wall; reactor vessel support/pedestal structure	Reduction of strength; loss of mechanical properties due to irradiation (i.e., radiation interactions with material and radiation-induced heating)	Plant-specific aging management program or plant-specific enhancements to selected AMPs	Yes (SRP-SLR Section 3.5.2.2.2.6)	A plant-specific AMP or plant-specific enhancement to an existing AMP is not required. See further evaluation in Section 3.5.2.2.2.6.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapters II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-098	Stainless steel, aluminum alloy support members; welds; bolted connections; support anchorage to building structure	None	None	No	Not applicable. Boric acid corrosion is not an aging effect requiring management for stainless steel or aluminum alloy. The associated NUREG-2191 aging items are not used.
3.5.1-099	Aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion; cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.S3, ASME Section XI, Subsection IWF, or AMP XI.M36, External Surfaces Monitoring of Mechanical Components	Yes (SRP-SLR Section 3.5.2.2.2.4)	Consistent with NUREG-2191 with exceptions. Loss of material and cracking of stainless steel elements is managed by the ASME Section XI, Subsection IWF (B2.1.32) program. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWF (B2.1.32) program implementation. See further evaluation in Section 3.5.2.2.2.4.
3.5.1-100	Aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion; cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.S6, Structures Monitoring, or AMP XI.M36, External Surfaces Monitoring of Mechanical Components	Yes (SRP-SLR Section 3.5.2.2.2.4)	Consistent with NUREG-2191. Loss of material and cracking of aluminum, stainless steel elements is managed by the Structures Monitoring (B2.1.35) program. In addition, components in Auxiliary Systems (material handling) are aligned to this row. See further evaluation in Section 3.5.2.2.2.4.

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Results Tables: Containment, Structures and Component Supports AMR Results

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB;SS	Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-38	3.5.1-010	C, 6
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-38	3.5.1-010	C, 6
				Loss of preload	10 CFR Part 50, Appendix J (B2.1.33)	III.A3.TP-261	3.5.1-088	E, 6, 7
					ASME Section XI, Subsection IWE (B2.1.30)	III.A3.TP-261	3.5.1-088	E, 6, 7
		Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-148	3.5.1-031	A
					Structures Monitoring (B2.1.35)	III.A4.TP-248	3.5.1-080	A
				Loss of preload	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-150	3.5.1-030	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-150	3.5.1-030	A
					Structures Monitoring (B2.1.35)	III.A4.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	A

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB;JIS;MB;PB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A4.TP-204	3.5.1-043	A, 1
						III.A4.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A4.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A4.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-67	3.5.1-012	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-67	3.5.1-012	A, 1
					ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-33	3.5.1-019	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-68	3.5.1-021	A, 1
						II.A1.CP-97	3.5.1-023	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-97	3.5.1-023	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-87	3.5.1-016	A, 1
						II.A1.CP-100	3.5.1-024	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-100	3.5.1-024	A, 1
				Loss of material (spalling, scaling) and cracking	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-147	3.5.1-011	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-147	3.5.1-011	A, 1
					ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-31	3.5.1-018	A, 1
			(E) Groundwater	Cracking	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-67	3.5.1-012	A, 1

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB;JIS;MB;PB;SS	Concrete	(E) Groundwater	Cracking	Structures Monitoring (B2.1.35)	II.A1.CP-67	3.5.1-012	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-100	3.5.1-024	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-100	3.5.1-024	A, 1
				Loss of material (spalling, scaling) and cracking	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-147	3.5.1-011	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-147	3.5.1-011	A, 1
			(E) Soil	Cracking	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-67	3.5.1-012	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-67	3.5.1-012	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-97	3.5.1-023	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-97	3.5.1-023	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-100	3.5.1-024	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-100	3.5.1-024	A, 1
				Loss of material (spalling, scaling) and cracking	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-147	3.5.1-011	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-147	3.5.1-011	A, 1
			(E) Water – flowing	Cracking; loss of bond; and loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-97	3.5.1-023	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-97	3.5.1-023	A, 1
				Increase in porosity and permeability; loss of strength	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-102	3.5.1-014	A, 1
					Structures Monitoring (B2.1.35)	II.A1.CP-102	3.5.1-014	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.CP-32	3.5.1-020	A, 1
					Structures Monitoring (B2.1.35)	III.A1.TP-67	3.5.1-047	A, 1
						III.A1.TP-24	3.5.1-063	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	ASME Section XI, Subsection IWL (B2.1.31)	VII.G.A-90	3.3.1-060	E, 1, 8
					Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Containment liner	PB;SS	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	II.A3.C-13	3.5.1-009	A, 2
				Loss of material	10 CFR Part 50, Appendix J (B2.1.33)	II.A1.CP-98	3.5.1-005	A, 2
					ASME Section XI, Subsection IWE (B2.1.30)	II.A1.CP-98	3.5.1-005	A, 2
					10 CFR Part 50, Appendix J (B2.1.33)	II.A1.CP-35	3.5.1-035	A, 2
					ASME Section XI, Subsection IWE (B2.1.30)	II.A1.CP-35	3.5.1-035	A, 2
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.1.T-25	3.5.1-089	C, 2
Equipment hatch, personnel access air lock, personnel escape air lock, and accessories (hinges, pins, closure mechanisms)	EN;FB;MB;PB;SS	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-37	3.5.1-027	A
				Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-39	3.5.1-029	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.C-16	3.5.1-028	A
			(E) Air – outdoor	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-37	3.5.1-027	A
				Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-39	3.5.1-029	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.C-16	3.5.1-028	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C
Moisture barriers	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-40	3.5.1-026	A, 3

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Penetrations (electrical)	PB;SS	Dissimilar metal welds	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-38	3.5.1-010	A
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-37	3.5.1-027	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-36	3.5.1-035	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-38	3.5.1-010	A
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-37	3.5.1-027	A
		Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-37	3.5.1-027	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-36	3.5.1-035	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Penetrations (mechanical)	PB;SS	Dissimilar metal welds	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-38	3.5.1-010	A
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-37	3.5.1-027	A
				Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	II.A3.C-13	3.5.1-009	A, 11
				Loss of material	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-36	3.5.1-035	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-38	3.5.1-010	A
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-37	3.5.1-027	A
				Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	II.A3.C-13	3.5.1-009	A, 11
		Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-37	3.5.1-027	A
				Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	II.A3.C-13	3.5.1-009	A, 11
				Loss of material	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-36	3.5.1-035	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C
Primary shield wall	EN;SS	Concrete	(E) Air – indoor uncontrolled	Reduction of strength; loss of mechanical properties	None	III.A4.T-35	3.5.1-097	12
Refueling cavity/fuel transfer canal liner	BWI;PB;SS	Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	C
			(E) Treated borated water	Cracking; loss of material	Structures Monitoring (B2.1.35)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B2.1.2)	III.A5.T-14	3.5.1-078	A

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Seals and gaskets	PB	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-41	3.5.1-033	A, 4
Service Level I coatings	MCI	Coatings	(E) Air – indoor uncontrolled	Loss of coating or lining integrity	Protective Coating Monitoring and Maintenance (B2.1.37)	II.A3.CP-152	3.5.1-034	A
						III.A4.TP-301	3.5.1-073	A
Steel elements	EN;FB;FLB;JIS;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A4.TP-302	3.5.1-077	A, 5
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C, 5
Sump liners	PB;SS	Dissimilar metal welds	(E) Air – indoor uncontrolled	Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	II.A3.C-13	3.5.1-009	A, 10
		Stainless steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	II.A3.C-13	3.5.1-009	A, 10
			(E) Water – standing	Cracking; loss of material	ASME Section XI, Subsection IWE (B2.1.30)	III.A7.T-23	3.5.1-052	E, 9
Tendon anchorage components	SS	Steel	(E) Air – outdoor	Loss of material	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.C-10	3.5.1-032	A
Tendons	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWL (B2.1.31)	II.A1.C-10	3.5.1-032	A
				Loss of prestress	TLAA	II.A1.C-11	3.5.1-008	A

Table 3.5.2-1 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, curbs, foundations, pads, jet impingement barriers, missile barriers, tendon access gallery, dome, ring girder and buttresses.
2. Containment liner includes liner plates, liner leak chase channels, liner anchors, and integral attachments.
3. Moisture barriers includes elastomeric moisture barrier between Containment liner and internal concrete basement floor.
4. Seals and gaskets include O-rings and other elastomer materials that are part of the Containment pressure boundary.

5. Steel elements include beams, columns, baseplates, bracing, stairs, platforms, grating, decking, ladders, missile barriers, and embedded steel.

6. Stainless steel bolting is associated with electrical penetrations.

7. The ASME Section XI, Subsection IWE (B2.1.30) program and 10 CFR Part 50, Appendix J (B2.1.33) program have been substituted for the Structures Monitoring (B2.1.35) program to manage the applicable aging effect(s) for this component type, material, and environment combination.

8. The ASME Section XI, Subsection IWL (B2.1.31) program has been substituted for the Structures Monitoring (B2.1.35) program to manage the applicable aging effect(s) for this component type, material, and environment combination.

9. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the ASME Section XI, Subsection IWE (B2.1.30) program.

10. The sump liners are part of the containment pressure boundary.

11. Applicable to the main steam containment penetrations.

12. As discussed in Section 3.5.2.2.2.6, analysis has determined that reduction of strength and loss of mechanical properties due to irradiation will not impact the primary shield wall's intended function under design basis conditions. Therefore, an AMP is not required to manage this aging effect. The other aging effects that are assigned to "Concrete elements" with an air-indoor uncontrolled environment are also applicable to the primary shield wall concrete.

Table 3.5.2-2 Structures and Component Supports - Auxiliary Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bellows	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-38	3.5.1-010	A, 1
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-38	3.5.1-010	A, 1
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-37	3.5.1-027	A, 1
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-37	3.5.1-027	A, 1
Bolting	SS	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	A, 5
		Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	A
Caulking and sealants	EN	Elastomer, rubber and other similar materials	(E) Air – outdoor	Loss of sealing	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	III.A6.TP-7	3.5.1-072	E, 6

Table 3.5.2-2 Structures and Component Supports - Auxiliary Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 2
						III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 2
						III.A3.TP-27	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 2
						III.A3.TP-27	3.5.1-065	A, 2

Table 3.5.2-2 Structures and Component Supports - Auxiliary Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 2
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 2
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 2
						III.A3.TP-24	3.5.1-063	A, 2
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 2
					Structures Monitoring (B2.1.35)	VII.G.A-90	3.3.1-060	A, 2
Containment liner	PB	Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.33)	II.A3.CP-37	3.5.1-027	A, 3
					ASME Section XI, Subsection IWE (B2.1.30)	II.A3.CP-37	3.5.1-027	A, 3
				Loss of material	10 CFR Part 50, Appendix J (B2.1.33)	II.A1.CP-98	3.5.1-005	A, 3
					ASME Section XI, Subsection IWE (B2.1.30)	II.A1.CP-98	3.5.1-005	A, 3
					10 CFR Part 50, Appendix J (B2.1.33)	II.A1.CP-35	3.5.1-035	A, 3
					ASME Section XI, Subsection IWE (B2.1.30)	II.A1.CP-35	3.5.1-035	A, 3
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.2.T-25	3.5.1-089	C, 3
Doors	EN;FB;FLB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C
Masonry block walls	EN;FLB	Concrete block	(E) Air – outdoor	Cracking	Masonry Walls (B2.1.34)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.34)	III.A3.TP-34	3.5.1-071	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-2 Structures and Component Supports - Auxiliary Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Steel elements	EN;FB;FLB; MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 4
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 4
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C, 4

Table 3.5.2-2 Plant-Specific Notes:

1. Bellows are associated with the isolation valve chambers and guard pipes (reactor building spray and residual heat removal).
2. Concrete elements include beams, columns, walls, slabs, foundation, duct banks, missile shields, knockdown walls, and pads.
3. The isolation valve chambers and guard pipes (reactor building spray and residual heat removal) are extensions of the Containment pressure boundary.
4. Steel elements include beams, columns, ladders, grating, siding, blow-off panels, stairs, missile shields, baseplates, and embedded steel.
5. Aluminum bolting is associated with blow-off panels.
6. The Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program has been substituted for the Structures Monitoring (B2.1.35) program to manage this aging effect for the caulking used at the tank external surface and concrete foundation interface for the refueling water storage tank and the reactor make-up water storage tank.

Table 3.5.2-3 Structures and Component Supports - Auxiliary Service Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-3 Structures and Component Supports - Auxiliary Service Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
						III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1

Table 3.5.2-3 Structures and Component Supports - Auxiliary Service Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 1
						III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-31	3.5.1-046	A, 1
Doors	EN	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.34)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.34)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.34)	III.A3.TP-34	3.5.1-071	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-3 Plant-Specific Notes:

1. Concrete elements include beams, walls, slabs, foundation, and pads.
2. Steel elements include beams, columns, siding, decking, baseplates, and embedded steel.

Table 3.5.2-4 Structures and Component Supports - Circulating Water Intake Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-4 Structures and Component Supports - Circulating Water Intake Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A3.TP-30	3.5.1-044	A
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1

Table 3.5.2-4 Structures and Component Supports - Circulating Water Intake Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;SS	Concrete	(E) Soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 1
						III.A3.TP-24	3.5.1-063	A, 1
				Loss of material	Structures Monitoring (B2.1.35)	III.A6.T-20	3.5.1-056	E, 1, 4
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-31	3.5.1-046	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.35)	VII.G.A-90	3.3.1-060	A, 1
Doors	EN;FB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
Masonry block walls	EN;FB;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.34)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.34)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.34)	III.A3.TP-34	3.5.1-071	A
		Masonry walls	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-626	3.3.1-179	A
					Masonry Walls (B2.1.34)	VII.G.A-626	3.3.1-179	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-4 Structures and Component Supports - Circulating Water Intake Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Steel elements	EN;FLT;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Water – flowing	Loss of material	Structures Monitoring (B2.1.35)	III.A6.TP-221	3.5.1-083	E, 2, 4
			(E) Water – standing	Loss of material	Structures Monitoring (B2.1.35)	III.A6.TP-221	3.5.1-083	E, 2, 4

Table 3.5.2-4 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, foundation, and pads.
2. Steel elements include beams, columns, grating, baseplates, and embedded steel.
3. Aluminum elements include louvers and screens.
4. The Structures Monitoring (B2.1.35) program has been substituted for the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program to manage the applicable aging effect(s) for this component type, material, and environment combination.

Table 3.5.2-5 Structures and Component Supports - Component Supports - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN;SS	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	A, 1
						III.B3.T-37b	3.5.1-100	A, 1
						III.B4.T-37b	3.5.1-100	A, 1
						III.B5.T-37b	3.5.1-100	A, 1
Bolting	SS	Stainless steel	(E) Raw water	Loss of preload	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.2.TP-229	3.5.1-087	B
					Structures Monitoring (B2.1.35)	III.B2.TP-261	3.5.1-088	A
						III.B5.TP-261	3.5.1-088	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.B2.TP-248	3.5.1-080	A
						III.B3.TP-248	3.5.1-080	A
						III.B4.TP-248	3.5.1-080	A
						III.B5.TP-248	3.5.1-080	A
					ASME Section XI, Subsection IWF (B2.1.32)	III.B1.2.TP-226	3.5.1-081	B
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.2.TP-229	3.5.1-087	B
					Structures Monitoring (B2.1.35)	III.B2.TP-261	3.5.1-088	A
						III.B3.TP-261	3.5.1-088	A
						III.B4.TP-261	3.5.1-088	A
						III.B5.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.B2.TP-248	3.5.1-080	A
						III.B3.TP-248	3.5.1-080	A
						III.B4.TP-248	3.5.1-080	A
						III.B5.TP-248	3.5.1-080	A
					ASME Section XI, Subsection IWF (B2.1.32)	III.B1.2.TP-226	3.5.1-081	B
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.2.TP-229	3.5.1-087	B
					Structures Monitoring (B2.1.35)	III.B2.TP-261	3.5.1-088	A
						III.B3.TP-261	3.5.1-088	A
						III.B4.TP-261	3.5.1-088	A
						III.B5.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.2.T-25	3.5.1-089	A
						III.B2.T-25	3.5.1-089	A

Table 3.5.2-5 Structures and Component Supports - Component Supports - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B3.T-25	3.5.1-089	A
						III.B4.T-25	3.5.1-089	A
						III.B5.T-25	3.5.1-089	A
			(E) Raw water	Loss of preload	Structures Monitoring (B2.1.35)	III.B2.TP-261	3.5.1-088	A
						III.B5.TP-261	3.5.1-088	A
Grout	SS	Grout	(E) Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.35)	III.B1.2.TP-42	3.5.1-055	A
						III.B2.TP-42	3.5.1-055	A
						III.B3.TP-42	3.5.1-055	A
						III.B4.TP-42	3.5.1-055	A
						III.B5.TP-42	3.5.1-055	A
			(E) Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.35)	III.B1.2.TP-42	3.5.1-055	A
						III.B2.TP-42	3.5.1-055	A
						III.B3.TP-42	3.5.1-055	A
						III.B4.TP-42	3.5.1-055	A
						III.B5.TP-42	3.5.1-055	A
Sliding surfaces	SS	Lubrite	(E) Air – indoor uncontrolled	Loss of mechanical function	Structures Monitoring (B2.1.35)	III.B2.TP-46	3.5.1-074	A
					ASME Section XI, Subsection IWF (B2.1.32)	III.B1.2.TP-45	3.5.1-075	B
Spring hangers; guides; stops	SS	Steel	(E) Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.2.T-28	3.5.1-057	B
					Structures Monitoring (B2.1.35)	III.B1.2.T-28	3.5.1-057	E, 4
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.2.T-25	3.5.1-089	A
						III.B2.T-25	3.5.1-089	A
Stainless steel elements	EN;SS	Stainless steel	(E) Air	Loss of material; cracking	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.2.T-36b	3.5.1-099	B, 2
					Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	A, 2
						III.B4.T-37b	3.5.1-100	A, 2

Table 3.5.2-5 Structures and Component Supports - Component Supports - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.2.T-24	3.5.1-091	B, 3
					Structures Monitoring (B2.1.35)	III.B2.TP-43	3.5.1-092	A, 3
						III.B3.TP-43	3.5.1-092	A, 3
						III.B4.TP-43	3.5.1-092	A, 3
						III.B5.TP-43	3.5.1-092	A, 3
			(E) Air – outdoor	Loss of material	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.2.T-24	3.5.1-091	B, 3
					Structures Monitoring (B2.1.35)	III.B2.TP-43	3.5.1-092	A, 3
						III.B3.TP-43	3.5.1-092	A, 3
						III.B4.TP-43	3.5.1-092	A, 3
						III.B5.TP-43	3.5.1-092	A, 3
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.2.T-25	3.5.1-089	A, 3
						III.B2.T-25	3.5.1-089	A, 3
						III.B3.T-25	3.5.1-089	A, 3
						III.B4.T-25	3.5.1-089	A, 3
						III.B5.T-25	3.5.1-089	A, 3
Vibration isolation elements	SS	Non-metallic (e.g., rubber)	(E) Air – indoor uncontrolled	Reduction or loss of isolation function	Structures Monitoring (B2.1.35)	III.B4.TP-44	3.5.1-094	A

Table 3.5.2-5 Plant-Specific Notes:

1. Aluminum elements include support members, cable trays, and conduits.
2. Stainless steel elements include support members, cable trays, and conduits.
3. Steel elements include support members, bearing plates, baseplates, connections, cable trays, conduits, instrument racks, and structural frames.
4. The Structures Monitoring (B2.1.35) program has been substituted for the ASME Section XI, Subsection IWF (B2.1.32) program to manage the aging effects applicable to this component type, material, and environment combination for non-ASME supports.

Table 3.5.2-6 Structures and Component Supports - Control Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-6 Structures and Component Supports - Control Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
						III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1

Table 3.5.2-6 Structures and Component Supports - Control Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 1
						III.A3.TP-24	3.5.1-063	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.35)	VII.G.A-90	3.3.1-060	A, 1
Doors	EN;FB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;FB;FLB; MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-6 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, foundation, duct banks, knockdown walls, missile shields, and pads.
2. Steel elements include beams, columns, ladders, grating, stairs, missile shields, baseplates, and embedded steel.

Table 3.5.2-7 Structures and Component Supports - Diesel Generator Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	C, 1
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-7 Structures and Component Supports - Diesel Generator Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 2
						III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 2
						III.A3.TP-27	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 2
						III.A3.TP-27	3.5.1-065	A, 2

Table 3.5.2-7 Structures and Component Supports - Diesel Generator Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 2
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 2
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 2
						III.A3.TP-24	3.5.1-063	A, 2
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 2
					Structures Monitoring (B2.1.35)	VII.G.A-90	3.3.1-060	A, 2
Doors	EN;FB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;FB;FLB; MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-7 Plant-Specific Notes:

1. Aluminum elements include louvers and screens.
2. Concrete elements include beams, columns, walls, slabs, foundation, caissons, duct banks, knockdown walls, missile shields, and pads.
3. Steel elements include beams, columns, ladders, grating, stairs, missile shields, baseplates, and embedded steel.

Table 3.5.2-8 Structures and Component Supports - Duct Banks - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A
						III.A3.TP-25	3.5.1-054	A
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A
						III.A3.TP-23	3.5.1-064	A
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A
						III.A3.TP-27	3.5.1-065	A
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A3.TP-30	3.5.1-044	A
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A
						III.A3.TP-27	3.5.1-065	A
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-24	3.5.1-063	A

Table 3.5.2-8 Plant-Specific Notes: None

Table 3.5.2-9 Structures and Component Supports - Earthen Embankments - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Earthen dike and embankment	BWI;SCW;SS	Earthfill (rip-rap, stone, soil)	(E) Air – outdoor	Loss of material; loss of form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-22	3.5.1-058	A
			(E) Water – flowing	Loss of material; loss of form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-22	3.5.1-058	A
			(E) Water – standing	Loss of material; loss of form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-22	3.5.1-058	A

Table 3.5.2-9 Plant-Specific Notes: None

Table 3.5.2-10 Structures and Component Supports - Electrical Manholes - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-10 Structures and Component Supports - Electrical Manholes - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
						III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1

Table 3.5.2-10 Structures and Component Supports - Electrical Manholes - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;MB;SS	Concrete	(E) Soil	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 1
						III.A3.TP-24	3.5.1-063	A, 1
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-10 Plant-Specific Notes:

1. Concrete elements include walls, slabs, foundations, and pads.
2. Steel elements include manhole covers, ladders, and embedded steel.

Table 3.5.2-11 Structures and Component Supports - Electrical Substation and Transformer Areas - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-11 Structures and Component Supports - Electrical Substation and Transformer Areas - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
						III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-24	3.5.1-063	A, 1

Table 3.5.2-11 Structures and Component Supports - Electrical Substation and Transformer Areas - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Doors	EN	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.34)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.34)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.34)	III.A3.TP-34	3.5.1-071	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
Steel elements	SS	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-11 Plant-Specific Notes:

1. Concrete elements include foundations, walls, pads, roofs, and slabs.
2. Steel elements include beams, columns, plates, trusses, poles, and embedded steel.

Table 3.5.2-12 Structures and Component Supports - Fuel Handling Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	C, 5
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	A

Table 3.5.2-12 Structures and Component Supports - Fuel Handling Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
						III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1

Table 3.5.2-12 Structures and Component Supports - Fuel Handling Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 1
						III.A3.TP-24	3.5.1-063	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.35)	VII.G.A-90	3.3.1-060	A, 1
Doors	EN;FB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C
Fuel storage rack neutron-absorbing sheets	AN	Boral; boron steel, and other materials (excluding Boraflex)	(E) Treated borated water	Reduction of neutron-absorbing capacity; change in dimensions and loss of material	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B2.1.27)	VII.A2.AP-235	3.3.1-102	A, 4
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
Spent fuel pool liner plates	EN;PB;SS	Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B5.T-37b	3.5.1-100	A
			(E) Treated borated water	Cracking; loss of material	Structures Monitoring (B2.1.35)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B2.1.2)	III.A5.T-14	3.5.1-078	A
Stainless steel elements	EN;PB;SS	Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B5.T-37b	3.5.1-100	A, 3
			(E) Treated borated water	Cracking; loss of material	Water Chemistry (B2.1.2)	III.A5.T-14	3.5.1-078	C, 3

Table 3.5.2-12 Structures and Component Supports - Fuel Handling Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Steel elements	EN;FB;FLB; MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C, 2

Table 3.5.2-12 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, foundation, caissons, piers, knockdown walls, missile shields, and pads.
2. Steel elements include beams, columns, ladders, grating, stairs, siding, missile shields, baseplates, and embedded steel.
3. Stainless steel elements include fuel transfer canal gate, new fuel storage racks, and spent fuel storage racks.
4. Boral panels are incorporated into the storage racks as a neutron-absorbing material.
5. Aluminum elements include wall panel framing.

Table 3.5.2-13 Structures and Component Supports - Intermediate Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	A, 3
		Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	A

Table 3.5.2-13 Structures and Component Supports - Intermediate Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
						III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1

Table 3.5.2-13 Structures and Component Supports - Intermediate Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 1
						III.A3.TP-24	3.5.1-063	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.35)	VII.G.A-90	3.3.1-060	A, 1
Doors	EN;FB;FLB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;FB;FLB; MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C, 2

Table 3.5.2-13 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, foundation, caissons, piers, duct banks, missile shields, and pads.
2. Steel elements include beams, columns, ladders, grating, siding, blow-off panels, stairs, missile shields, baseplates, and embedded steel.
3. Aluminum bolting is associated with blow-off panels.

Table 3.5.2-14 Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.B3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.B3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.B3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.B3.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B3.T-25	3.5.1-089	A
Electrical Enclosures	EN;LB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.B3.TP-43	3.5.1-092	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.B3.TP-43	3.5.1-092	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B3.T-25	3.5.1-089	C

Table 3.5.2-14 Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fireproofing and fire barriers	EN;FB;FLB	Cementitious coatings (Pyrocrete, BIO® K-10 Mortar, Cafecote, and other similar materials)	(E) Air	Loss of material; cracking/delamination; change in material properties; separation	Fire Protection (B2.1.15)	VII.G.A-806	3.3.1-268	A, 1, 2, 3
		Elastomer	(E) Air	Hardening, loss of strength, shrinkage	Fire Protection (B2.1.15)	VII.G.A-19	3.3.1-057	A, 1
		Silicates (Marinite®, Kaowool,®, Cerafiber®, Cera® blanket, or other similar materials)	(E) Air	Loss of material; cracking/delamination; change in material properties; separation	Fire Protection (B2.1.15)	VII.G.A-807	3.3.1-269	A, 1, 2
		Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	C, 1
		Subliming compounds (Thermo-lag ®, Darmatt®, 3M® Interam®, and other similar materials)	(E) Air	Loss of material; cracking/delamination; change in material properties; separation	Fire Protection (B2.1.15)	VII.G.A-805	3.3.1-267	A, 1, 2
Guard pipes	EN	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.B5.TP-43	3.5.1-092	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	A

Table 3.5.2-14 Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Penetration seals	EN;FB;FLB;PB	Elastomer	(E) Air	Hardening, loss of strength, shrinkage	Fire Protection (B2.1.15)	VII.G.A-19	3.3.1-057	A
		Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Groundwater	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Soil	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
Penetration sleeves	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.B3.TP-43	3.5.1-092	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.B3.TP-43	3.5.1-092	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B3.T-25	3.5.1-089	C
Seismic gap filler material	EN;FB	Elastomer	(E) Air	Hardening, loss of strength, shrinkage	Fire Protection (B2.1.15)	VII.G.A-19	3.3.1-057	C
		Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-14 Plant-Specific Notes:

1. Fireproofing and fire barriers include fire stops, fire wraps, fire barrier seals, coatings, and radiant energy shields.
2. Aging management of change of material properties is applicable to fireproofing and fire barriers exposed to radiation dose greater than 1 x 10^6 rads.
3. Change of material properties and loss of material due to elevated temperature are not applicable to cementitious coatings since these fireproofing and fire barrier materials are not exposed to an environment where the general area temperature exceeds 150°F (65.6°C) or the local area temperature exceeds 200°F (93.3°C).

Table 3.5.2-15 Structures and Component Supports - NSSS Supports - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	High-strength steel	(E) Air	Cracking	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.1.TP-41	3.5.1-068	B
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.1.TP-229	3.5.1-087	B
		Stainless steel	(E) Air	Loss of material; cracking	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.1.T-36b	3.5.1-099	B
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.1.TP-229	3.5.1-087	B
		Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.1.TP-226	3.5.1-081	B
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.1.TP-229	3.5.1-087	B
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.1.T-25	3.5.1-089	A
Grout	SS	Grout	(E) Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.35)	III.B1.1.TP-42	3.5.1-055	A
Sliding surfaces	SS	Lubrite	(E) Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.1.TP-45	3.5.1-075	B, 3
Spring hangers; guides; stops	SS	Steel	(E) Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.1.T-28	3.5.1-057	B
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.1.T-25	3.5.1-089	A
Stainless steel elements	SS	Stainless steel	(E) Air	Loss of material; cracking	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.1.T-36b	3.5.1-099	B, 1
Steel elements	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B2.1.32)	III.B1.1.T-24	3.5.1-091	B, 2
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.1.T-25	3.5.1-089	A, 2

Table 3.5.2-15 Plant-Specific Notes:

1. Stainless steel elements include support members.
2. Steel elements include support members, bearing plates, baseplates, and connections.
3. Lubrite sliding surfaces have been used in ASME Class 1 pipe supports. Lubrite sliding surfaces are not used in the reactor vessel supports.

Table 3.5.2-16 Structures and Component Supports - Service Water Discharge Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	MB;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-38	3.5.1-059	A, 1
					Structures Monitoring (B2.1.35)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-110	3.5.1-049	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-36	3.5.1-060	A, 1
			(E) Groundwater	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-107	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-110	3.5.1-049	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A6.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-107	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-110	3.5.1-049	A, 1

Table 3.5.2-16 Structures and Component Supports - Service Water Discharge Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	MB;SS	Concrete	(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A6.TP-109	3.5.1-051	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-20	3.5.1-056	A, 1
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-36	3.5.1-060	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-31	3.5.1-046	A, 1

Table 3.5.2-16 Plant-Specific Notes:

1. Concrete elements include beams, walls, slabs, and foundations.

Table 3.5.2-17 Structures and Component Supports - Service Water Intake Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-261	3.5.1-088	E, 3
			(E) Water – standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-261	3.5.1-088	E, 3

Table 3.5.2-17 Structures and Component Supports - Service Water Intake Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	MB;PB;SS	Concrete	(E) Groundwater	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-107	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-110	3.5.1-049	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A6.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-107	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-110	3.5.1-049	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A6.TP-109	3.5.1-051	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-20	3.5.1-056	A, 1
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-36	3.5.1-060	A, 1

Table 3.5.2-17 Structures and Component Supports - Service Water Intake Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	MB;PB;SS	Concrete	(E) Water – flowing	Reduction of foundation strength and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-31	3.5.1-046	A, 1
Steel elements	FLT;SS	Steel	(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	C, 2
			(E) Water – standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	C, 2

Table 3.5.2-17 Plant-Specific Notes:

1. Concrete elements include beams, walls, slabs, and foundations.
2. Steel elements include trash racks, ladders, and embedded steel.
3. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program instead of the Structures Monitoring (B2.1.35) program will manage the loss of preload for bolting.

Table 3.5.2-18 Structures and Component Supports - Service Water Pumphouse - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	C, 1
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-261	3.5.1-088	E, 4
			(E) Air – outdoor	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-261	3.5.1-088	E, 4
			(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-261	3.5.1-088	E, 4
			(E) Water – standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-261	3.5.1-088	E, 4

Table 3.5.2-18 Structures and Component Supports - Service Water Pumphouse - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 2
						III.A6.TP-25	3.5.1-054	A, 2
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-34	3.5.1-096	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-38	3.5.1-059	A, 2
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-37	3.5.1-061	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 2
						III.A6.TP-25	3.5.1-054	A, 2
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-34	3.5.1-096	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-38	3.5.1-059	A, 2
					Structures Monitoring (B2.1.35)	III.A6.TP-104	3.5.1-065	A, 2
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-37	3.5.1-061	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-110	3.5.1-049	A, 2
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-36	3.5.1-060	A, 2
			(E) Groundwater	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-104	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-107	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-110	3.5.1-049	A, 2

Table 3.5.2-18 Structures and Component Supports - Service Water Pumphouse - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 2
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A6.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-104	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A6.TP-107	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-110	3.5.1-049	A, 2
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A6.TP-220	3.5.1-050	A, 2
						III.A6.TP-25	3.5.1-054	A, 2
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-34	3.5.1-096	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-38	3.5.1-059	A, 2
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A6.TP-109	3.5.1-051	A, 2
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-37	3.5.1-061	A, 2
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.T-20	3.5.1-056	A, 2
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-36	3.5.1-060	A, 2
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.35)	III.A6.TP-31	3.5.1-046	A, 2
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 2
					Structures Monitoring (B2.1.35)	VII.G.A-90	3.3.1-060	A, 2
Doors	EN;FB;FLB; MB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-18 Structures and Component Supports - Service Water Pumphouse - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Steel elements	EN;FLT;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	C, 3
			(E) Air – outdoor	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	C, 3
			(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	C, 3
			(E) Water – standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36)	III.A6.TP-221	3.5.1-083	C, 3

Table 3.5.2-18 Plant-Specific Notes:

1. Aluminum elements include louvers and screens.
2. Concrete elements include beams, columns, walls, slabs, foundation, duct banks, missile shields, and pads.
3. Steel elements include ladders, grating, stairs, beams, missile shields, baseplates, grating, trash racks, and embedded steel.
4. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.36) program instead of the Structures Monitoring (B2.1.35) program will manage the loss of preload for bolting.

Table 3.5.2-19 Structures and Component Supports - Tank and Equipment Foundations - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
Caulking and sealants	EN	Elastomer, rubber and other similar materials	(E) Air – outdoor	Loss of sealing	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	III.A6.TP-7	3.5.1-072	E, 2

Table 3.5.2-19 Structures and Component Supports - Tank and Equipment Foundations - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
						III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-24	3.5.1-063	A, 1

Table 3.5.2-19 Plant-Specific Notes:

1. Concrete elements include walls, slabs, and foundations.
2. The Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program has been substituted for the Structures Monitoring (B2.1.35) program to manage this aging effect for the caulking used at the Condensate Storage Tank external surface and concrete foundation interface.

Table 3.5.2-20 Structures and Component Supports - Turbine Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-20 Structures and Component Supports - Turbine Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
						III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1

Table 3.5.2-20 Structures and Component Supports - Turbine Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;SS	Concrete	(E) Soil	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 1
						III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-31	3.5.1-046	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.35)	VII.G.A-90	3.3.1-060	A, 1
Doors	EN;FB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
Masonry block walls	EN;FB;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.34)	III.A3.T-12	3.5.1-070	A
		Masonry walls	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-626	3.3.1-179	A
					Masonry Walls (B2.1.34)	VII.G.A-626	3.3.1-179	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;FB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-20 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, foundation, duct banks, and pads.

2. Steel elements include beams, columns, ladders, stairs, siding, decking, baseplates, grating, and embedded steel.

3. Aluminum elements include louvers, screens, and wall panel framing.

Table 3.5.2-21 Structures and Component Supports - Water Treatment Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.35)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.35)	III.A3.TP-261	3.5.1-088	A

Table 3.5.2-21 Structures and Component Supports - Water Treatment Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
						III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.35)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-212	3.5.1-065	A, 1

Table 3.5.2-21 Structures and Component Supports - Water Treatment Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.35)	III.A3.TP-29	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-108	3.5.1-042	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.35)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.35)	III.A3.TP-67	3.5.1-047	A, 1
						III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.35)	III.A3.TP-31	3.5.1-046	A, 1
Doors	EN	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.34)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.34)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.34)	III.A3.TP-34	3.5.1-071	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.35)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-21 Plant-Specific Notes:

1. Concrete elements include beams, walls, slabs, foundation, and pads.
2. Steel elements include beams, columns, siding, decking, baseplates, and embedded steel.

3. Aluminum elements include louvers, screens, and wall panel framing.

Tables 3.5.2-1 through 3.5.2-21 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

F. Material not in NUREG-2191 for this component.

G. Environment not in NUREG-2191 for this component and material.

H. Aging effect not in NUREG-2191 for this component, material and environment combination.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

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3.6 AGING MANAGEMENT OF ELECTRICAL AND INSTRUMENTATION AND CONTROLS

3.6.1 INTRODUCTION

This section provides the results of the aging management review for components and commodities identified in Section 2.5.1, Electrical Component Groups as being subject to aging management review. Components and commodities addressed in this section are described in the indicated sections.

- Cable Bus (Section 2.5.1.1)
- Cables And Connections (Section 2.5.1.2)
- High Voltage Insulators (Section 2.5.1.3)

3.6.2 RESULTS

The following tables summarize the results of the aging management review for Electrical and Instrumentation and Controls.

- Table 3.6.2-1, Electrical and Instrumentation and Controls - Cable Bus - Aging Management Evaluation
- Table 3.6.2-2, Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation
- Table 3.6.2-3, Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation

3.6.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.6.2.1.1 Cable Bus

Materials

The materials of construction for the cable bus subcomponents are:

- Aluminum
- Electrical insulation

Environment

The cable bus subcomponents are exposed to the following environments:

- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor

Aging Effects Requiring Management

The following aging effects, associated with the cable bus subcomponents, require management:

- Loss of material
- Reduced electrical insulation resistance

Aging Management Programs

The following aging management programs manage the aging effects for the cable bus subcomponents:

- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.38)
- Structures Monitoring (B2.1.35)

3.6.2.1.2 Cables And Connections

Materials

The materials of construction for the cables and connections subcomponents are:

- Aluminum
- Electrical insulation
- Galvanized steel
- Stainless steel
- Steel
- Various metals used for electrical connections
- Various metals used for electrical contacts
- Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield

Environment

The cables and connections subcomponents are exposed to the following environments:

- Adverse localized environment caused by heat, radiation, or moisture
- Adverse localized environment caused by significant moisture
- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects, associated with the cables and connections subcomponents, require management:

- Increased electrical resistance of connection
- Loss of conductor strength
- Loss of material
- Reduced electrical insulation resistance
- Reduced electrical insulation resistance or degraded dielectric strength

Aging Management Programs

The following aging management programs manage the aging effects for the cables and connections subcomponents:

- Boric Acid Corrosion (B2.1.4)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.44)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.38)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B2.1.39)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.41)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.42)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.40)
- Fuse Holders (B2.1.43)

3.6.2.1.3 High Voltage Insulators

Materials

The materials of construction for the high voltage insulators subcomponents are:

- Porcelain

Environment

The high voltage insulators subcomponents are exposed to the following environments:

- Air – outdoor

Aging Effects Requiring Management

The following aging effects, associated with the high voltage insulators subcomponents, require management:

- Loss of material
- Reduced electrical insulation resistance

Aging Management Programs

The following aging management programs manage the aging effects for the high voltage insulators subcomponents:

- High-Voltage Insulators (B2.1.45)

3.6.2.2 Further Evaluation of Aging Management as Recommended by NUREG-2192

NUREG-2192 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the Subsequent License Renewal Application. For the auxiliary systems, those evaluations are addressed in the following sections.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

Environmental qualification is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed separately in Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," of this SRP-SLR.

[3.6.1-001] - Environmental qualification is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed in Section 4.4, Environmental Qualification of Electric Equipment.

3.6.2.2.2 Reduced Insulation Resistance Due to Age Degradation of Cable Bus Arrangements Caused by Intrusion of Moisture, Dust, Industrial Pollution, Rain, Ice, Photolysis, Ohmic Heating and Loss of Strength of Support Structures and Louvers of Cable Bus Arrangements Due to General Corrosion and Exposure to Air Outdoor

Reduced insulation resistance due to age degradation of cable bus caused by intrusion of moisture, dust, industrial pollution, rain, ice, photolysis (for ultraviolet sensitive material only), ohmic heating and loss of strength of support structures, covers or louvers of cable bus arrangements due to general corrosion or exposure to air outdoor could occur in cable bus assemblies. Cable bus is a variation of metal enclosed bus (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, and 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 GALL-SLR Report AMP (e.g., GALL-SLR Report AMP XI.E1 and AMP XI.E4). 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. 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 applicable to cable bus aging mechanisms and effects. Therefore, the GALL-SLR Report recommends cable bus aging mechanisms and effects be evaluated as a plant-specific further evaluation. The evaluation includes associated AMPs: AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," and AMP XI.S6, "Structures Monitoring." Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-SLR).

As discussed in NUREG-2191 and NUREG-2192, cable bus is treated as a separate commodity type. A subset of electrical cables and connections are identified as cable bus in NUREG-2191. The discussion in NUREG-2192 addresses aging effects on cable bus. Cable bus is a variation on metal enclosed bus (MEB) which is similar in construction to an MEB, but instead of segregated or non-segregated electrical buses, cable bus is comprised of a metallic cable bus enclosure that utilizes three-phase insulated power cables installed with cable separator blocks.

Bus duct or cable bus is part of the electrical system, and this system is in-scope for subsequent license renewal. Cable bus performs the intended functions of conducts electricity, insulates, and enclosure protection to supply electrical power to safety-related switchgear. The in-scope cable bus supplies off-site power to electrical buses for both off-site power paths. Cable bus is routed from the engineered safety features transformer XFT-4 to the safety-related electrical switchgear, and cable bus is routed from the emergency auxiliary transformer XFT-31 to the safety-related electrical switchgear.

The cable bus insulated electrical cables are routed through a cable bus enclosure fabricated of aluminum, with louvered (slotted) bottom panels, and solid sides and top covers. The cable bus enclosure supports are fabricated of aluminum and steel. The cable bus insulated cables are installed with cable separator blocks (internal to the enclosure) that are fabricated of aluminum and composite materials. These cable supports do not perform as insulators since the cable bus cables are insulated and jacketed just like cables in a cable tray. Cable bus is routed both indoors and outdoors.

The outdoor cable bus is routed above ground, in aluminum cable bus enclosures that are designed to be weatherproof. The bottom panels have louvers (slots) in them so that moisture and dirt will not be able to collect in the cable bus enclosure, and for the outdoor installations, the cable bus enclosures have solid top and side panels to limit exposure to weather (ambient temperature, humidity, and UV from direct sunlight). The cable bus insulated electrical cables are jacketed and insulated and has no aging mechanisms in this location different from insulated cables in cable tray. Dirt and debris are not expected to be an issue because the slots in the bottom panel are not large, and gravity will generally prevent entry of any dirt beyond minor surface dust. Moisture could enter the cable bus enclosures (via heavy rain), but it will have no impact on the cable bus insulated electrical cables because it cannot collect in the cable bus enclosure, as it will drain out the slots at the bottom. The cable bus insulated electrical cables are continuous runs with connections only at endpoints or cable bus tap boxes.

For the cable bus routed indoors, the aluminum cable bus enclosures are also routed above ground. The indoor cable bus enclosure design is the same as the outdoor cable bus enclosure, with louvers (slots) in the bottom panels. There is no pathway for moisture to collect in the cable bus enclosure, and any dirt that enters the cable bus enclosure will be minor surface dust only. The cable bus electrical insulated cables will not be impacted by minor surface dust or by the ambient temperature and humidity levels; the air-indoor environment is considered a benign environment for insulated electrical cables and the aluminum cable bus enclosures. The cable bus insulated electrical cables are jacketed and insulated and has no aging mechanisms in this location different from insulated cables in cable tray.

The cable bus electrical insulated cable connections are included in the cable connections (metallic parts) component group.

[3.6.1-029] - Reduced electrical insulation resistance for the cable bus insulated electrical cables is the same as other installed insulated electrical cables. This item is similar to electrical insulation for electrical cables and connections item 3.6.1-008, so this aging effect will be managed by the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.38) program.

[3.6.1-030] - Loss of material for cable bus enclosures with steel in an air – indoor uncontrolled, or air – outdoor can be caused by age related degradation. There are no cable bus enclosures made from steel. Therefore, this aging effect is not applicable.

[3.6.1-031] - Loss of material for cable bus enclosures with galvanized steel; or aluminum in an air-outdoor environment can be caused by age related degradation. In-scope cable bus enclosures made from aluminum are located outside. This item is similar to metal enclosed bus enclosure item 3.6.1-015, which recommends Structures Monitoring as an aging management program. This aging effect will be managed by the Structures Monitoring (B2.1.35) program.

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload for Transmission Conductors, Switchyard Bus, and Connections

Loss of material due to wind-induced abrasion, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections. The GALL SLR Report recommends further evaluation of a plant-specific AMP to demonstrate that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Loss of material due to wind-induced abrasion, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections.

Transmission conductors are uninsulated (bare), stranded electrical cables used in switchyards and switching stations 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. The transmission conductor commodity group includes the associated fastening hardware but excludes the high-voltage insulators, which are addressed separately. Transmission connectors, which are addressed as a separate component, provide connections at transmission conductor endpoints.

Switchyard bus is the uninsulated, 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. Switchyard bus includes the connections and hardware used to secure the bus to endpoints (e.g., high-voltage insulators, transmission conductors, etc.).

The switchyard bus and connections, transmission conductors and transmission connectors are those credited for recovery of offsite power following a station blackout event. Other switchyard bus and transmission conductors are not subject to aging management review since it does not perform or support subsequent license renewal intended functions. Overhead transmission conductors credited for recovery of offsite power following a station blackout event operate at transmission voltage (230 kV) and would typically be referred to as overhead transmission conductors and overhead transmission conductor connectors. However, for consistency in terminology, they will be referred to as transmission conductors and transmission connectors.

[3.6.1-004] - Loss of conductor strength due to corrosion is applicable for aluminum conductor steel reinforced (ACSR) conductors. The in-scope 230 kV transmission conductors are bare 795 thousand circular mils (kcmil) (45/7) ACSR (Tern) conductors.

In-scope 230 kV transmission conductors are limited to short length spans of 795 kcmil (45/7) ACSR conductors between the high-voltage side of the emergency auxiliary transformer (XTF-31) and the 230 kV circuit breaker (XCB-8892) used for recovery of offsite power following an SBO event. The longest span of 795 kcmil (45/7) ACSR between support towers is approximately 386 ft. Also included is a short span (~25 ft.) of 1272 kcmil (45/7) ACSR for the connection from the 230kV boundary beaker XCB-8892 to the isolation switch XDS-8893.

The most prevalent mechanism contributing to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires.

Corrosion in ACSR conductors is a very slow-acting aging mechanism with the corrosion rates depending largely on air quality, which includes suspended particles chemistry, sulfur dioxide concentration in air, precipitation, fog chemistry, and meteorological conditions. Air quality in non-coastal rural areas, such as the area surrounding the plant, generally contains low concentrations of suspended particles and sulfur dioxide, which minimizes the corrosion rate. There are no major industries in the immediate area where the plant is located, so this is a considered a typical rural area.

Regarding the loss of strength of transmission conductors, tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion. The Subsequent License Renewal Electrical Handbook makes statements relative to transmission conductor aged strengths based upon testing performed by Ontario Hydroelectric.

The specific transmission conductor construction type at VCSNS is bounded by the Ontario Hydroelectric test, so the results of this test are representative of the VCNSN 230 kV transmission conductors.

There is set percentage of composite conductor strength established at which a transmission conductor is replaced. As illustrated below, there is ample strength margin to maintain the transmission conductor intended function through the subsequent period of extended operation.

The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature. These requirements are reviewed concerning the specific transmission conductors included in the scope of subsequent license renewal.

Evaluation of the conductor type with the smallest ultimate strength margin (4/0 ACSR, 6/1) in the NESC illustrates the conservative nature of the design of the transmission conductors required for offsite power recovery. The 4/0 (212 kcmil) 6/1 ACSR conductor has only one steel reinforcement conductor, so the impacts of corrosion on this one steel reinforcement conductor is more severe than a transmission conductor with multiple steel reinforcement conductors.

The ultimate strength and the NESC heavy load tension requirements of 4/0 ACSR are 8350 lbs. and 2761 lbs. respectively. The margin between the NESC heavy load and the ultimate strength is 5589 lb.; i.e., there is a 67 percent of ultimate strength margin. The Ontario Hydroelectric study showed a 30 percent loss of composite conductor strength in an 80-year-old conductor. In the case of the 4/0 ACSR transmission conductors, a 30 percent loss of ultimate strength would mean that there would still be a 37 percent ultimate strength margin between what is required by the NESC and the actual conductor strength. The 4/0 ACSR conductor type has the lowest initial design margin of transmission conductors included in the AMR. This illustrates with reasonable assurance that the 230 kV transmission conductors will have ample strength through the period of extended operation.

A review of industry operating experience and NRC generic communications related to the aging of transmission conductors ensured that no additional aging effects exist beyond those previously identified. A review of plant-specific operating experience did not identify any unique aging effects for transmission conductors.

Therefore, loss of conductor strength due to corrosion is not an aging effect requiring management for the 230 kV ACSR transmission conductors.

[3.6.1-005] - Increased electrical resistance of connection due to oxidation or loss of preload is not applicable for aluminum and stainless-steel transmission connectors.

The in-scope 230 kV transmission connectors are limited to the 795 kcmil (45/7) ACSR transmission conductors between the high-voltage side of the emergency auxiliary transformer (XTF-31) and the 230 kV circuit breaker (XCB-8892) used for recovery of offsite power following an SBO event.

The 230 kV aluminum transmission conductor connections are treated with corrosion inhibitors to avoid connection oxidation. Connections are assembled using stainless steel bolts, lock washers, and nuts. The connections are torqued when installed to avoid loss of preload.

Based on design and confirmed by plant-specific operating experience, oxidation and loss of preload are not applicable aging mechanisms for transmission conductor connections.

[3.6.1-006] - Loss of material due to wind induced abrasion and increased electrical resistance of connection due to oxidation or loss of preload are not applicable for aluminum and stainless-steel components exposed to outdoor air environments in the switchyard bus and connections component group.

The in-scope 115 kV and 230 kV switchyard bus are bare five (5) inch iron pipe size schedule 80 aluminum switchyard bus. The 115 kV switchyard bus is installed from the ESF transformer (XTF-4) to the 115kV PARR ESF circuit switcher (XES 4), which is the boundary isolation device.

The 230 kV switchyard bus is installed between the 230 kV transmission conductors to the high-voltage side of the emergency auxiliary transformer (XTF-31).

The aluminum tubular switchyard bus and aluminum angle switchyard bus are supported by active components and station post insulators mounted on steel structures in concrete foundations. Connections between switchyard bus and active components such as circuit breakers, disconnects and transformers are either directly terminated or connected by short lengths of flexible ACSR conductors that are not typically subject to vibration under wind loading. Switchyard bus is not subject to abrasion induced by wind loading due to its rigid mounting.

The plant is located in a rural area on a man-made, freshwater lake. Salt spray and salt coating have not been experienced on switchyard components. There are no nearby industrial facilities that produce airborne industrial effluents. Aluminum bus material does not experience any appreciable aging effects in this environment.

Most of the aluminum switchyard bus has welded connections. The aluminum switchyard bolted connections are treated with corrosion inhibitors to avoid connection oxidation. Connection hardware is either aluminum or stainless steel. Connections that are assembled using stainless-steel bolts and nuts include lock washers and are torqued to prevent loss of preload.

A review of industry operating experience and NRC generic communications related to the aging of switchyard bus and connections ensured that no additional aging effects exist beyond those previously identified. A review of plant-specific operating experience did not identify any unique aging effects for switchyard bus and connections.

Based on design and confirmed by plant-specific operating experience, wind-induced abrasion, and increased resistance of connection due to oxidation and loss of preload are not applicable aging mechanisms for switchyard bus and connections.

[3.6.1-007] - Loss of material due to wind-induced abrasion is not applicable for aluminum conductor steel reinforced (ACSR) conductors exposed to outdoor air environments in the Transmission Conductors component group.

There are no in-scope all aluminum conductor (AAC) or aluminum conductor aluminum reinforced (ACAR) transmission conductors in the Transmission Conductor component group. The in-scope 230 kV transmission conductors are bare 795 kcmil (45/7) ACSR conductors.

In-scope 230 kV transmission conductors are limited to short length spans of 795 kcmil (45/7) ACSR conductors between the emergency auxiliary transformer (XTF-31) and the 230 kV circuit breaker (XCB-8892) used for recovery of offsite power following an SBO event. The longest span of 795 kcmil (45/7) ACSR between support towers is approximately 386 ft. Also included is a short span (~25 ft.) of 1272 kcmil (45/7) ACSR for the connection from the 230kV boundary beaker XCB-8892 to the isolation switch XDS-8893.

Transmission conductor vibration, or sway, could be caused by wind loading. Experience has shown that transmission conductors do not normally swing significantly. When transmission conductors do swing due to a substantial wind, they do not continue to swing for very long once the wind has subsided. Wind loading that can cause a transmission conductor to vibrate or sway is considered in design and installation. Transmission conductors that are in-scope for subsequent license renewal are installed with shorter spans, at lower elevations, and with less sag than typical transmission conductors. Thus, they tend to be less affected by wind loading than typical transmission conductors.

A review of industry operating experience and NRC generic communications related to the aging of transmission conductors ensured that no additional aging effects exist beyond those previously identified. A review of plant-specific operating experience did not identify any unique aging effects for transmission conductors.

Based on design and confirmed by plant-specific operating experience, loss of material due wind-induced abrasion is not an applicable aging effect for transmission conductors.

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.6.2.2.5 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

Results Tables: Electrical and Instrumentation and Controls Commodity Groups

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-001	Electrical equipment subject to 10 CFR 50.49 EQ requirements composed of various polymeric and metallic materials in plant areas subject to a harsh environment (i.e., loss of coolant accident (LOCA), high energy line break (HELB), or post LOCA environment or; An adverse localized environment for the most limiting qualified condition for temperature, radiation, or moisture for the component material (e.g., cable or connection insulation).	Various aging effects due to various mechanisms in accordance with 10 CFR 50.49	EQ is a time-limited aging analysis (TLAA) to be evaluated for the subsequent period of extended operation. See the Standard Review Plan, Section 4.4, Environmental Qualification (EQ) of Electric Equipment, for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)(i) and (ii). See AMP X.E1, Environmental Qualification (EQ) of Electric Equipment, of this report for meeting the requirements of 10 CFR 54.21(c)(1)(i)-(iii).	Yes, TLAA (SRP-SLR Section 3.6.2.2.1)	Consistent with NUREG-2191. Environmental Qualification is a TLAA. See further evaluation in Section 3.6.2.2.1.
3.6.1-002	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers; silicone rubber; fiber glass, aluminum alloy exposed to air – outdoor	Loss of material on metallic connectors due to mechanical wear caused by movement of transmission conductors due to significant wind	AMP XI.E7, High-Voltage Insulators	No	Consistent with NUREG-2191.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-003	High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers; silicone rubber; fiber glass, aluminum alloy exposed to air – outdoor	Reduced electrical insulation resistance due to presence of salt deposits or surface contamination; peeling of silicone rubber sleeves for polymer insulators; or degradation of glazing on porcelain insulators	AMP XI.E7, High-Voltage Insulators	No	Consistent with NUREG-2191.
3.6.1-004	Transmission conductors composed of aluminum; steel exposed to air – outdoor	Loss of conductor strength due to corrosion	A plant-specific aging management program is to be evaluated for ACSR	Yes (SRP-SLR Section 3.6.2.2.3)	The NUREG-2191 aging effect of loss of conductor strength exposed to an air-outdoor environment is not applicable. See further evaluation in Section 3.6.2.2.3.
3.6.1-005	Transmission connectors composed of aluminum; steel exposed to air – outdoor	Increased electrical resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.3)	The NUREG-2191 aging effect of increased electrical resistance of connection for aluminum and steel transmission connectors exposed to an air-outdoor environment is not applicable. See further evaluation in Section 3.6.2.2.3.
3.6.1-006	Switchyard bus and connections composed of aluminum; copper; bronze; stainless steel; galvanized steel exposed to air – outdoor	Loss of material due to wind-induced abrasion; Increased electrical resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.3)	The NUREG-2191 aging effect of loss of material and increased electrical resistance of connection for aluminum, stainless steel, and galvanized steel exposed to an air-outdoor environment is not applicable. See further evaluation in Section 3.6.2.2.3.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-007	Transmission conductors composed of aluminum; steel exposed to air – outdoor	Loss of material due to wind-induced abrasion	A plant-specific aging management program is to be evaluated for All Aluminum Conductor (AAC), ACAR and ACSR	Yes (SRP-SLR Section 3.6.2.2.3)	The NUREG-2191 aging effect of loss of material for aluminum and steel transmission conductors exposed to an air-outdoor environment is not applicable. See further evaluation in Section 3.6.2.2.3.
3.6.1-008	Electrical insulation for electrical cables and connections (including terminal blocks, etc.) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to an adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E1, Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Consistent with NUREG-2191.
3.6.1-009	Electrical insulation for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance (IR) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to an adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E2, Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	No	Consistent with NUREG-2191.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-010	Electrical conductor insulation for inaccessible power, instrumentation, and control cables (e.g., installed in duct bank, buried conduit or direct buried) composed of various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield exposed to an adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength due to significant moisture	AMP XI.E3A, Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements, AMP XI.E3B, Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements, or AMP XI.E3C, Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements	No	Consistent with NUREG-2191. Reduced electrical insulation resistance or degraded dielectric strength is managed by the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.41) program, the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.42) program or the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.40) program.
3.6.1-011	Metal enclosed bus: enclosure assemblies composed of elastomers exposed to air – indoor controlled or uncontrolled, air – outdoor	Surface cracking, crazing, scuffing, dimensional change (e.g. ballooning and necking), shrinkage, discoloration, hardening or loss of strength due to elastomer degradation	AMP XI.E4, Metal Enclosed Bus, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. There are no in-scope metal enclosed bus: enclosure assemblies. The associated NUREG-2191 aging items are not used.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-012	Metal enclosed bus: bus/connections composed of various metals used for electrical bus and connections exposed to air – indoor controlled or uncontrolled, air – outdoor	Increased electrical resistance of connection due to the loosening of bolts caused by thermal cycling and ohmic heating	AMP XI.E4, Metal Enclosed Bus	No	Not applicable. There are no in-scope metal enclosed bus: bus/connections. The associated NUREG-2191 aging items are not used.
3.6.1-013	Metal enclosed bus: electrical insulation; insulators composed of porcelain; xenoy; thermo-plastic organic polymers exposed to air – indoor controlled or uncontrolled, air – outdoor	Reduced electrical insulation resistance due to thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, and ohmic heating	AMP XI.E4, Metal Enclosed Bus	No	Not applicable. There are no in-scope metal enclosed bus: electrical insulation; insulators composed of porcelain; xenoy; thermo-plastic organic polymers. The associated NUREG-2191 aging items are not used.
3.6.1-014	Metal enclosed bus: external surface of enclosure assemblies composed of steel exposed to air – indoor uncontrolled, air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.E4, Metal Enclosed Bus, or AMP XI.S6, Structures Monitoring	No	Not applicable. There are no in-scope metal enclosed bus. The associated NUREG-2191 aging items are not used.
3.6.1-015	Metal enclosed bus: external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor	Loss of material due to pitting, crevice corrosion	AMP XI.E4, Metal Enclosed Bus, or AMP XI.S6, Structures Monitoring	No	Not applicable. There are no in-scope metal enclosed bus. The associated NUREG-2191 aging items are not used.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-016	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor uncontrolled	Increased electrical resistance of connection due to chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection due to chemical contamination, corrosion and oxidation do not apply)	AMP XI.E5, Fuse Holders - No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms and effects due to chemical contamination, corrosion, and oxidation.	No	Consistent with NUREG-2191. Increased electrical resistance of connection of fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor controlled or uncontrolled is managed by the Fuse Holders (B2.1.43) program.
3.6.1-017	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air-indoor controlled or uncontrolled	Increased electrical resistance of connection due to fatigue from ohmic heating, thermal cycling, electrical transients	AMP XI.E5, Fuse Holders - No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue due to ohmic heating, thermal cycling, electrical transients.	No	Consistent with NUREG-2191. Increased electrical resistance of connection of fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor controlled or uncontrolled is managed by the Fuse Holders (B2.1.43) program.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-018	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor controlled or uncontrolled	Increased electrical resistance of connection due to fatigue caused by frequent fuse removal/manipulation or vibration	AMP XI.E5, Fuse Holders - No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue caused by frequent fuse removal/manipulation or vibration.	No	Consistent with NUREG-2191. Increased electrical resistance of connection of fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor controlled or uncontrolled is managed by the Fuse Holders (B2.1.43) program.
3.6.1-019	Cable connections (metallic parts) composed of various metals used for electrical contacts exposed to air – indoor controlled or uncontrolled, air – outdoor	Increased electrical resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	AMP XI.E6, Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Consistent with NUREG-2191.
3.6.1-020	Electrical connector contacts for electrical connectors composed of various metals used for electrical contacts exposed to air with borated water leakage	Increased electrical resistance of connection due to corrosion of connector contact surfaces caused by intrusion of borated water	AMP XI.M10, Boric Acid Corrosion	No	Consistent with NUREG-2191.
3.6.1-021	Transmission conductors composed of aluminum exposed to air – outdoor	Loss of conductor strength due to corrosion	None - for ACAR and All Aluminum Conductor (AAC)	No	Not applicable. Loss of conductor strength of transmission conductors exposed to air – outdoor is addressed in rows 3.6.1-004 and 3.6.1-007. The associated NUREG-2191 aging items are not used.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-022	Fuse holders (not part of active equipment): insulation material composed of electrical insulation material: bakelite; phenolic melamine or ceramic; molded polycarbonate, and other, exposed to air – indoor controlled or uncontrolled	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E5, Fuse Holders - No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms	No	Consistent with NUREG-2191. Reduced electrical insulation resistance of fuse holders (not part of active equipment): insulation material exposed to air – indoor controlled or uncontrolled is managed by the Fuse Holders (B2.1.43) program.
3.6.1-023	Metal enclosed bus: external surface of enclosure assemblies. Galvanized steel; aluminum. air – indoor controlled or uncontrolled	None	None	No	Not applicable. There are no in-scope metal enclosed bus. The associated NUREG-2191 aging items are not used.
3.6.1-024	Metal enclosed bus: external surface of enclosure assemblies. Steel air – indoor controlled	None	None	No	Not applicable. There are no in-scope metal enclosed bus. The associated NUREG-2191 aging items are not used.
3.6.1-027	Cable bus: external surface of enclosure assemblies galvanized steel; aluminum; air – indoor controlled or uncontrolled	None	None	No	Consistent with NUREG-2191.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-029	Cable bus: electrical insulation; insulators – exposed to air – indoor controlled or uncontrolled, air – outdoor	Reduced electrical insulation resistance due to degradation caused thermal/ thermoxidative degradation of organics and photolysis (UV sensitive materials only) of organics, moisture/debris intrusion and ohmic heating	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Consistent with NUREG-2191. The plant specific aging management program used to manage reduced electrical insulation resistance of cable bus: electrical insulation; insulators – exposed to air – indoor controlled or uncontrolled, air – outdoor is Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.38) program. See further evaluation in Section 3.6.2.2.2.
3.6.1-030	Cable bus: external surface of enclosure assemblies composed of steel exposed to air – indoor uncontrolled or air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Not applicable. Loss of material of cable bus: external surface of enclosure assemblies exposed to air – indoor uncontrolled or air – outdoor is addressed in row 3.6.1-031. The associated NUREG-2191 aging items are not used.
3.6.1-031	Cable bus external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Consistent with NUREG-2191. The plant specific aging management program used to manage loss of material of cable bus external surface of enclosure assemblies composed of aluminum exposed to air – outdoor is Structures Monitoring (B2.1.35) program. See further evaluation in Section 3.6.2.2.2.
3.6.1-032	Cable bus: external surface of enclosure assemblies: composed of steel; air – indoor controlled	None	None	No	Not applicable. There are no in-scope cable bus: external surface of enclosure assemblies: composed of steel; air – indoor controlled in the Electrical and Instrumentation and Controls. The associated NUREG-2191 aging items are not used.

Results Tables: Electrical and Instrumentation and Controls AMR Results

Table 3.6.2-1 Electrical and Instrumentation and Controls - Cable Bus - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Cable bus enclosure assembly (includes Tap Box enclosure)	EN	Aluminum	(E) Air – indoor uncontrolled	None	None	VI.A.L-09	3.6.1-027	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.35)	VI.A.L-13	3.6.1-031	E, 1
Cable bus insulation, insulators	IN	Electrical insulation	(E) Air – indoor controlled	Reduced electrical insulation resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.38)	VI.A.L-11	3.6.1-029	E, 1
			(E) Air – indoor uncontrolled	Reduced electrical insulation resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.38)	VI.A.L-11	3.6.1-029	E, 1
			(E) Air – outdoor	Reduced electrical insulation resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.38)	VI.A.L-11	3.6.1-029	E, 1

Table 3.6.2-1 Plant-Specific Notes:

1. The Inspection of Cable Bus Components plant specific program has been substituted by the Structures Monitoring (B2.1.35) program and the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.38) program to manage the applicable aging effects for cable bus components.

Table 3.6.2-2 Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Cable connections (metallic parts)	CE	Various metals used for electrical contacts	(E) Air – indoor controlled	Increased electrical resistance of connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.44)	VI.A.LP-30	3.6.1-019	A, 5
			(E) Air – indoor uncontrolled	Increased electrical resistance of connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.44)	VI.A.LP-30	3.6.1-019	A, 5
			(E) Air – outdoor	Increased electrical resistance of connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.44)	VI.A.LP-30	3.6.1-019	A, 5
Connector contacts for electrical connections exposed to borated water leakage	CE	Various metals used for electrical contacts	(E) Air with borated water leakage	Increased electrical resistance of connection	Boric Acid Corrosion (B2.1.4)	VI.A.LP-36	3.6.1-020	A
Fuse Holder - Not Part of Active Equipment (Insulation Material)	IN	Electrical insulation: bakelite; phenolic melamine or ceramic; molded polycarbonate; other	(E) Air – indoor controlled	Reduced electrical insulation resistance	Fuse Holders (B2.1.43)	VI.A.LP-24	3.6.1-022	A
			(E) Air – indoor uncontrolled	Reduced electrical insulation resistance	Fuse Holders (B2.1.43)	VI.A.LP-24	3.6.1-022	A
Fuse Holder - Not Part of Active Equipment (Metallic Clamps)	CE	Various metals used for electrical connections	(E) Air – indoor controlled	Increased electrical resistance of connection	Fuse Holders (B2.1.43)	VI.A.L-07	3.6.1-017	A
						VI.A.LP-31	3.6.1-018	A
			(E) Air – indoor uncontrolled	Increased electrical resistance of connection	Fuse Holders (B2.1.43)	VI.A.LP-23	3.6.1-016	A
						VI.A.L-07	3.6.1-017	A
						VI.A.LP-31	3.6.1-018	A

Table 3.6.2-2 Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Insulation Material for Electrical Cable and Connections Used in Instrumentation Circuits	IN	Various organic polymers (e.g., EPR, SR, EPDM, XLPE)	() Adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B2.1.39)	VI.A.LP-34	3.6.1-009	A
Insulation Material for Electrical Cables and Connections	IN	Various organic polymers (e.g., EPR, SR, EPDM, XLPE)	(E) Adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.38)	VI.A.LP-33	3.6.1-008	A
Insulation Material for Inaccessible or Below Ground Instrumentation and Control Cable	IN	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield	() Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.41)	VI.A.LP-35b	3.6.1-010	A
Insulation Material for Inaccessible or Below Ground Low Voltage Power Cable	IN	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield	() Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.42)	VI.A.LP-35c	3.6.1-010	A

Table 3.6.2-2 Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Insulation Material for Inaccessible or Below Ground Medium Voltage Cable	IN	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield	() Adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.40)	VI.A.LP-35a	3.6.1-010	A
Switchyard bus and connections	CE	Aluminum	(E) Air – outdoor	Loss of material; increased electrical resistance of connection	None	VI.A.LP-39	3.6.1-006	I, 1
		Galvanized steel	(E) Air – outdoor	Loss of material; increased electrical resistance of connection	None	VI.A.LP-39	3.6.1-006	I, 1
		Stainless steel	(E) Air – outdoor	Loss of material; increased electrical resistance of connection	None	VI.A.LP-39	3.6.1-006	I, 1
Transmission conductors	CE	Aluminum, Steel	(E) Air – outdoor	Loss of conductor strength	None	VI.A.LP-38	3.6.1-004	I, 4
				Loss of material	None	VI.A.LP-47	3.6.1-007	I, 2
Transmission connectors	CE	Aluminum	(E) Air – outdoor	Increased electrical resistance of connection	None	VI.A.LP-48	3.6.1-005	I, 3
		Steel	(E) Air – outdoor	Increased electrical resistance of connection	None	VI.A.LP-48	3.6.1-005	I, 3

Table 3.6.2-2 Plant-Specific Notes:

1. Loss of material and increased electrical resistance of connection are not applicable aging effects for switchyard bus and connections. The in-scope switchyard bus and connections are subject to neither wind induced abrasion nor oxidation or loss of pre-load.

2. Loss of material is not an applicable aging effect for transmission conductors. The in-scope transmission conductors are not subject to wind induced abrasion.

3. Increased electrical resistance of connection is not an applicable aging effect for transmission connections. The in-scope transmission connections are not subject to oxidation or loss of pre-load.

4. Loss of conductor strength is not an applicable aging effect for transmission conductors. The in-scope transmission conductors are aluminum conductor steel reinforced (ACSR) transmission conductors.

5. Includes Tap box connections.

Table 3.6.2-3 Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
High Voltage Insulators	IN	Porcelain	(E) Air – outdoor	Loss of material	High-Voltage Insulators (B2.1.45)	VI.A.LP-32	3.6.1-002	A
				Reduced electrical insulation resistance	High-Voltage Insulators (B2.1.45)	VI.A.LP-28	3.6.1-003	A

Table 3.6.2-3 Plant-Specific Notes: None

Tables 3.6.2-1 through 3.6.2-4 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

F. Material not in NUREG-2191 for this component.

G. Environment not in NUREG-2191 for this component and material.

H. Aging effect not in NUREG-2191 for this component, material and environment combination.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

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4.0 TIME-LIMITED AGING ANALYSES

4.1 INTRODUCTION

Time-Limited Aging Analyses (TLAAs) are described in Title 10 of the Code of Federal Regulations (10 CFR) 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants" (Reference 1.7-2). This section provides the results of evaluations of TLAAs and any exemptions that are based on TLAAs. This section evaluates each identified TLAA in accordance with 10 CFR 54.21(c).

Section 4.1.1, Identification of Time-Limited Aging Analyses, provides the 10 CFR 54.3(a) definition of TLAAs, indicates the requirements for evaluation of TLAAs, and summarizes the process used for identifying TLAAs at Virgil C. Summer Nuclear Station Unit 1 (VCSNS). Later sections address related TLAA issues, including Section 4.1.2, Evaluation of Time-Limited Aging Analyses; Section 4.1.3, Acceptance Criteria; Section 4.1.4, Identification of Exemptions; and Section 4.1.5, Summary of Results.

Subsequent sections of this chapter describe the evaluation of TLAAs within the following categories:

- Reactor Vessel Neutron Embrittlement Analysis (Section 4.2)
- Metal Fatigue (Section 4.3)
- Environmental Qualification of Electric Equipment (Section 4.4)
- Concrete Containment Tendon Prestress Analysis (Section 4.5)
- Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis (Section 4.6)
- Other Plant-Specific Time-Limited Aging Analyses (Section 4.7)
- References (Section 4.8)

4.1.1 IDENTIFICATION OF TIME-LIMITED AGING ANALYSES

Title 10 CFR of the Code of Federal Regulations, Part 54, Section 54.3(a) defines time-limited aging analyses as follows:

"Time-limited aging analyses, for the purposes of this part, are those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a);

(2) Consider the effects of aging;

(3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;

(4) Were determined to be relevant by the licensee in making a safety determination;

(5) Involve conclusions or provides the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in 54.4(b); and

(6) Are contained or incorporated by reference in the current licensing basis (CLB)."

The TLAAs from initial license renewal and those identified as potential TLAAs were reviewed against the definition in 10 CFR 54.3(a) to determine whether they meet the definition of a TLAA for the subsequent period of extended operation.

In accordance with 10 CFR 54.21(c)(1), a license renewal application must contain a list of TLAAs, as defined in 10 CFR 54.3. The applicant shall demonstrate that -

(i) The analyses remain valid for the subsequent period of extended operation;

(ii) The analyses have been projected to the end of the subsequent period of extended operation; or

(iii) The effects of aging on the intended function(s) will be adequately managed for the subsequent period of extended operation.

This chapter provides the demonstration prescribed in 10 CFR 54.21(c)(1).

A list of potential TLAAs was compiled from regulatory and industry sources, including:

- NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report" (Reference 1.7-6)
- NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants" (Reference 1.7-5)
- NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal" (Reference 1.7-4)
- 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants" (Reference 1.7-2)
- Prior license renewal applications
- Plant-specific document reviews and interviews with plant personnel

Keyword searches were performed on the CLB documentation to determine whether these potential TLAAs exist in the CLB. The keyword search was also used to identify additional potential plant-specific TLAAs. The CLB search included:

- Changes to the Final Safety Analysis Report (FSAR) (Reference 1.7-18)
- Changes to the Technical Specifications and Bases (Reference 1.7-17)
- NRC Safety Evaluation Report (SER) for the initial renewed operating license
- Subsequent NRC Safety Evaluations (SEs)
- Docketed licensing correspondence between Dominion Energy South Carolina, Inc. (formerly South Carolina Electric & Gas Company) and the NRC

The potential TLAAs were then reviewed against the TLAA definition in 10 CFR 54.3(a). The review considered information in the CLB documents and from source documents for the potential TLAAs such as:

- Vendor, NRC-sponsored, and licensee topical reports
- Calculations
- Code stress reports or code design reports
- Drawings
- Specifications

Potential TLAAs that met all six elements of the 10 CFR 54.3(a) definition were identified as TLAAs that required evaluation for the subsequent period of extended operation.

4.1.2 EVALUATION OF TIME-LIMITED AGING ANALYSES

Each TLAA has been evaluated and the description of each evaluation includes the following information:

TLAA Description:

A description of the CLB analysis that has been identified as a TLAA, including a description of the associated aging effect and the time-limited assumption used in the analysis.

TLAA Evaluation:

The evaluation of the TLAA for the subsequent period of extended operation. This section provides the information associated with 80 years of operation for comparison with the information used in the related TLAA that considered the previous license term of operation. This evaluation provides the basis for the disposition, which will be one of the three options specified in 10 CFR 54.21(c)(1).

TLAA Disposition:

Each TLAA is demonstrated acceptable in accordance with one of the three options from 10 CFR 54.21(c)(1) specified in Section 4.1.3 below.

4.1.3 ACCEPTANCE CRITERIA

10 CFR 54.21, Contents of application - technical information, specifies that an application must contain the following information:

(c) An evaluation of time-limited aging analyses.

1. A list of time-limited aging analyses as defined in 10 CFR 54.3 must be provided. The applicant shall demonstrate that--
   - (i) The analyses remain valid for the subsequent period of extended operation;
   - (ii) The analyses have been projected to the end of the subsequent period of extended operation; or
   - (iii) The effects of aging on the intended function(s) will be adequately managed for the subsequent period of extended operation.

One of these three methods is used to disposition each TLAA identified. The methods used are identified in each TLAA evaluation section.

4.1.4 IDENTIFICATION OF EXEMPTIONS

10 CFR 54.21(c)(2) indicates a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on TLAAs as defined in 10 CFR 54.3 be provided with the license renewal application. An evaluation that justifies the continuation of these exemptions for the period of extended operation is also required to be provided.

Docketed licensing correspondence, the operating license, and the FSAR were searched to identify exemptions in effect. Each exemption in effect was then evaluated to determine whether it was based on a TLAA as defined in 10 CFR 54.3.

There were no 10 CFR 50.12 exemptions identified that are currently in effect that are based upon a TLAA.

4.1.5 SUMMARY OF RESULTS

The Generic TLAAs Listed in NUREG-2192, Table 4.1-2 and Table 4.7-1 and their applicability to VCSNS are shown in Table 4.1.5-1, Review of Generic TLAAs Listed in NUREG-2192, Table 4.1-2 and Table 4.7-1. The Generic TLAAs that apply to VCSNS are identified with a “Yes” and contain a link to the subsequent license renewal application (SLRA) section containing the TLAA evaluation. The Generic TLAAs that are not applicable are identified with a “No” and a link is not provided since no TLAA was identified for these categories either because they are associated with design features not employed or because no analysis was identified that meets all six elements of the TLAA definition in 10 CFR 54.3(a).

Sections 4.2 through Section 4.7 describe the evaluations of six general categories of TLAAs. Table 4.1.5-2, Time-Limited Aging Analyses Categories and Dispositions provides the TLAA categories and associated dispositions. The TLAA categories in Table 4.1.5-2 are provided in the order in which they appear in Sections 4.2 through Section 4.7 of NUREG-2192. The table entries also indicate the disposition method used to evaluate the TLAA and a link is provided to the SLRA section containing the TLAA evaluation for the subsequent period of extended operation.

Table 4.1.5-1 Review of Generic TLAAs Listed in NUREG-2192, Table 4.1-2 and Table 4.7-1

NUREG-2192, Table 4.1-2 - Generic TLAAs	Applies to VCSNS	TLAA Evaluation Section
Neutron Fluence	Yes	Section 4.2.1
Upper Shelf Energy (PWRs and BWRs)	Yes	Section 4.2.2
Pressurized Thermal Shock (PWRs Only)	Yes	Section 4.2.3
Pressure Temperature (P-T) Limits (PWRs and BWRs)	Yes	Section 4.2.4 Section 4.2.5
Low Temperature Overpressure Protection System Setpoints (PWRs Only)	Yes	Section 4.2.6
Ductility Reduction Evaluation for Reactor Internals (B&W designed PWRs only)	No	N/A
RV Circumferential Weld Relief-Probability of Failure and Mean Adjusted Reference Temperature Analysis for the RV Circumferential Welds (BWRs only)	No	N/A
Reactor Vessel Axial Weld Probability of Failure and Mean Adjusted Reference Temperature Analysis (BWRs only)	No	N/A
Metal Fatigue of Class 1 Components	Yes	Section 4.3.2
Metal Fatigue of Non-Class 1 Components	Yes	Section 4.3.3
Environmentally-Assisted Fatigue	Yes	Section 4.3.4
High-Energy Line Break Analyses	Yes	Section 4.3.5
Cycle-dependent Fracture Mechanics or Flaw Evaluations	Yes	Section 4.3.4
Cycle-dependent Fatigue Waivers	Yes	Section 4.3.2.6
Environmental Qualification of Electric Equipment	Yes	Section 4.4
Concrete Containment Tendon Prestress Analysis	Yes	Section 4.5
Containment Liner Plate, Metal Containments, and Penetrations Fatigue	Yes	Section 4.6

Table 4.1.5-1 Review of Generic TLAAs Listed in NUREG-2192, Table 4.1-2 and Table 4.7-1

NUREG-2192, Table 4.7-1 - Examples of Potential Plant Specific TLAA Topics	Applies to VCSNS	TLAA Evaluation Section
Reactor Pressure Vessel Underclad Cracking	No[a]	N/A
Leak-Before-Break	Yes	Section 4.7.3
Reactor Coolant Pump Flywheel Fatigue Crack Growth	Yes	Section 4.7.2
Response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification”	Yes	Section 4.3.2.8
Response to NRC Bulletin 88-08, “Thermal Stresses in Piping Connected to Reactor Cooling Systems”	No[b]	N/A
Fatigue of Cranes (Crane Cycle Limits)	Yes	Section 4.7.1
Fatigue of the Spent Fuel Pool Liner	No	N/A
Corrosion Allowance Calculations	No	N/A
Flaw Growth Due to Stress Corrosion Cracking	No	N/A
Predicted Lower Limit	No	N/A

Footnote(s):

(a) The reactor vessel (RV) is constructed of ASME SA-533 grade B, Class 1 (not susceptible) and ASME SA-508, Class 2 (with low-heat-input weld procedures). Therefore this aging effect is not applicable.

(b) No ASME Code, Section III cumulative usage factor (CUF) analyses were generated in response to NRC IEB 88-08. Ultrasonic inspections were performed in response to IEB 88-08.

Table 4.1.5-2 Time-Limited Aging Analyses Categories and Dispositions

TLAA Category	Analysis	Disposition (Note 1)	Section
REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSIS	Neutron Fluence Projections	(ii)	Section 4.2.1
	Upper-Shelf Energy	(ii)	Section 4.2.2
	Pressurized Thermal Shock	(ii)	Section 4.2.3
	Adjusted Reference Temperature	(ii)	Section 4.2.4
	Pressure-Temperature Limits	(iii)	Section 4.2.5
	Low Temperature Overpressure Protection	(i)	Section 4.2.6
METAL FATIGUE	Transient Cycle Projections for 80 years	Not Applicable	Section 4.3.1
	ASME Code, Section III, Class 1 Fatigue Analyses	See Section 4.3.2.1 through Section 4.3.2.6	Section 4.3.2
	Control Rod Drive Mechanism	(iii)	Section 4.3.2.1
	Pressurizer	(iii)	Section 4.3.2.2
	Reactor Coolant Pumps	(iii)	Section 4.3.2.3
	Reactor Vessel and Replacement Reactor Vessel Closure Head	(iii)	Section 4.3.2.4
	Steam Generators	(iii)	Section 4.3.2.5
	ASME Code, Section III, Class 1 Component Fatigue Waivers	(iii)	Section 4.3.2.6
	ASME Code, Section III, Class 1 Piping Fatigue Analyses	(i)	Section 4.3.2.7
	Pressurizer Surge Line	(i)	Section 4.3.2.8
	Non-Class 1 Allowable Stress Analyses	(i)	Section 4.3.3

Table 4.1.5-2 Time-Limited Aging Analyses Categories and Dispositions

TLAA Category	Analysis	Disposition (Note 1)	Section
METAL FATIGUE (cont'd.)	Environmentally-Assisted Fatigue	(iii)	Section 4.3.4
	High-Energy Line Break Analysis	(i)	Section 4.3.5
ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT	Environmental Qualification of Electric Equipment	(iii)	Section 4.4
CONCRETE CONTAINMENT TENDON PRESTRESS ANALYSIS	Concrete Containment Tendon Prestress Analysis	(iii)	Section 4.5
CONTAINMENT LINER PLATE, METAL CONTAINMENT & CONTAINMENT PENETRATIONS FATIGUE ANALYSIS	Containment Liner Plate	(ii)	Section 4.6.1
	Metal Containment	N/A	Section 4.6.2
	Containment Penetrations Fatigue Analysis	(i)	Section 4.6.3
OTHER PLANT-SPECIFIC TLAAS	Crane Load Cycle Limits	(i)	Section 4.7.1
	Reactor Coolant Pump Flywheel Fatigue Crack Growth Analyses	(i)	Section 4.7.2
	Leak-Before-Break	(ii)	Section 4.7.3
	Steam Generator Tube Wear Evaluation	(iii)	Section 4.7.4

Note 1:

(i) Validation: The analyses remain valid for the subsequent period of extended operation.

(ii) Projection: The analyses have been projected to the end of the subsequent period of extended operation.

(iii) Aging Management: The effects of aging on the intended function(s) will be adequately managed for the subsequent period of extended operation.

4.2 REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSIS

10 CFR 50.60, “Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Reactors for Normal Operation,” requires that all light water reactors meet the fracture toughness, pressure-temperature (P-T) limits, and materials surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H. The materials included in the surveillance capsule program remain unchanged for the subsequent period of extended operation based upon the provisions outlined in ASTM E185-73, “Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels,” (Reference 4.8-3) that existed at the time of plant construction. 10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events,” (Reference 1.7-15) requires that all light water reactors meet the fracture toughness requirements for protection against pressurized thermal shock (PTS) events. The Reactor Vessel Material Surveillance program is described in Section B2.1.19.

Inputs for reactor vessel (RV) integrity assessments are discussed in this section.

The best estimate copper (Cu) and nickel (Ni) chemical compositions for the RV materials are presented in Table 4.2.2-1. The best estimate weight percent (Wt.%) Cu and Ni values for the RV materials were reported in PWROG-21037-NP, “Determination of Unirradiated RT_{NDT} and Upper-Shelf Energy Values of the V.C. Summer Unit 1 Reactor Vessel Materials” (Reference 4.8-25) and were included in RV integrity evaluations as part of this TLAA effort.

Prior to updating the RV integrity assessments for the subsequent period of extended operation both the fluence projections and material properties were reviewed and updated by WCAP-18709-NP, “V. C. Summer Nuclear Station Unit 1 Subsequent License Renewal: Reactor Pressure Vessel Extended Beltline Neutron Exposure Evaluation” (Reference 4.8-32). Revised initial material properties, including chemistry factors (CF) and fluence projections, through 72 effective full-power years (EFPY) are included in Table 4.2.3-1.

The neutron fluence axial boundary of the 1.0 x 10^{17} n/cm^2 fluence threshold is depicted in Figure 4.2.2-1. The configuration of the RV is illustrated in Figure 4.2.2-2.

Reactor vessel integrity assessments are performed for both the beltline region (identified in 10 CFR 50, Appendix G) and extended beltline region (fluence values >1.0 x 10^{17} n/cm^2, E >1 MeV).

The beltline region is the region of the RV (shell material, including welds, heat-affected zones, and plate or forgings) that directly surrounds the effective height of the active core and the adjacent regions of the RV that are predicted to experience sufficient neutron irradiation damage to be considered in the selection of the most limiting material with regard to radiation damage during the licensed period.

The extended beltline means the region of the RV (shell material, including welds, heat-affected zones, and plate or forgings) adjacent to the beltline region that will have associated fluence values projected to exceed 1.0 x 10^{17} n/cm^2 during the subsequent period of extended operation.

The RV ferritic materials are subject to embrittlement due to high energy (E > 1.0 MeV) neutron exposure. Embrittlement means the material has lower toughness (i.e., will absorb less strain energy during crack propagation or rupture), thus allowing a crack to propagate more easily under thermal and pressure loading. Neutron embrittlement analyses account for the reduction in fracture toughness associated with the cumulative neutron fluence. These neutron embrittlement analyses use a fluence assumption based on the plant's current operating term, and therefore, are identified as TLAAs.

Fracture toughness (indirectly measured in foot-pounds of absorbed energy in a Charpy impact test) is temperature dependent in ferritic materials. An initial nil-ductility reference temperature (RT_{NDT}) is associated with the transition from ductile to brittle behavior and is determined for RV materials through a combination of Charpy and drop-weight testing. Toughness increases with temperature up to a maximum value called the “upper-shelf energy,” or USE. Neutron embrittlement results in the USE decrease of RV steels. This means that RV materials may no longer behave in a ductile manner at postulated plant operating temperatures. For beltline materials the limit for initial USE is 75 ft-lbs. The limit for reduced USE of beltline materials following irradiation is 50 ft-lbs. The material outside the beltline was originally qualified using the requirements of the codes in effect at the time of the design and fabrication of the RV, ASME Code, Section III, “Rules for Construction of Nuclear Facility Components” (Reference 4.8-4).

10 CFR 50.61 requirements for PTS events specify screening criteria of 270°F for plates, forgings, and axial welds and 300°F for circumferential welds. The PTS reference temperature (RT_{PTS}) values have been projected through the subsequent period of extended operation.

USE and RT_{PTS} calculations are performed for each beltline and extended beltline material to determine if the components will continue to have adequate fracture toughness with the reduction in toughness resulting from exposure to the predicted neutron fluence. All beltline and extended beltline materials are projected to satisfy the USE and RT_{PTS} requirements.

To reduce the potential for brittle fracture during RV operation, changes in material toughness as a function of neutron radiation exposure (fluence) are accounted for during development of operating pressure temperature (P-T) limits that are included in the Technical Specifications. The P-T limits account for the decrease in material toughness of RV materials during plant operation based upon the RT_{NDT} and ΔRT_{NDT} values computed for the licensed operating period along with appropriate margins. Since the cumulative neutron fluence will increase during the subsequent period of extended operation, a review is needed.

The enabling temperature and low temperature overpressure protection (LTOP) setpoints are validated as they are impacted by fluence.

The RV material evaluations, calculated on the basis of neutron fluence, are part of the CLB and support safety determinations. Therefore, these calculations have been identified as TLAAs.

The evaluations of TLAAs related to neutron embrittlement are described in the following subsections:

- Neutron Fluence Projections (Section 4.2.1)
- Upper-Shelf Energy (Section 4.2.2)
- Pressurized Thermal Shock (Section 4.2.3)
- Adjusted Reference Temperature (Section 4.2.4)
- Pressure-Temperature Limits (Section 4.2.5)
- Low Temperature Overpressure Protection (Section 4.2.6)

4.2.1 NEUTRON FLUENCE PROJECTIONS

TLAA Description:

Neutron fluence is the term used to represent the cumulative number of neutrons per square centimeter that contact the RV shell and other components. The fluence projections that quantify the number of neutrons that contact these surfaces have been used as inputs to the neutron embrittlement analyses that evaluate the reduction of fracture toughness aging effect resulting from neutron irradiation but will be conservatively treated as a TLAA for discussion purposes.

TLAA Evaluation:

License Amendment No. 174, “Virgil C. Summer Nuclear Station, Unit 1 - Issuance of Amendment Regarding Reactor Coolant System Pressure Temperature Limits (TAC No. MC7375)” (Reference 4.8-26), documents that RV beltline neutron fluence values applicable to the 60-year period of operation are summarized in WCAP-16305-NP, “V. C. Summer Heatup and Cooldown Limit Curves for Normal Operation” (Reference 4.8-10). These fluence values were taken from WCAP-16298-NP, “Analysis of Capsule Z from the South Carolina Electric & Gas Company V. C. Summer Reactor Vessel Radiation Surveillance Program” (Reference 4.8-8), and were determined in accordance with the USNRC-approved RV neutron fluence methodology described in WCAP-14040-A, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves” (Reference 4.8-19).

EFPY Projections

The first step in updating fluence projections for 80 years is to estimate the power history based on the actual operating history and a conservative capacity factor estimate for future cycles. V.C. Summer is currently licensed for 60 years of operation; therefore, with a 20-year license renewal, the subsequent license renewal term is 80 years.

The EFPY projections through the end of the subsequent period of extended operation is the sum of the accumulated EFPY and the projected future EFPY. The EFPY at the end of 60 years of operation is estimated to be 56 EFPY. The cumulative operating time as of April 2023 is 33.7 EFPY. A 72 EFPY projection was chosen for the end of the subsequent period of extended operation since it bounds the EFPY to date and is conservative when projecting the cumulative EFPY to 80 years. 72 EFPY is calculated as 34 (33.7 rounded up) + 40 (years of extended operation) * 0.95 (95% capacity factor).

Fluence Projections

Estimated RV beltline and extended beltline fast neutron (E > 1.0 MeV) fluences at the end of 80 years of operation were calculated in WCAP-18709-NP. The analyses methodologies used to calculate the RV fluences followed the guidance of Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence" (Reference 4.8-5). These methodologies have been approved by the NRC for the beltline region, i.e., materials directly surrounding the core and adjacent materials per 10 CFR 50, Appendix G, "Fracture Toughness Requirements. The beltline region is projected to experience the highest fluence. The beltline region has traditionally included the intermediate and lower shell forgings, and the circumferential welds between these components. The traditional beltline and extended beltline materials are identified in Table 4.2.1-1.

Materials exceeding a fast neutron (E > 1.0 MeV) fluence of 1.0×10^{17} n/cm^2 at the end of the subsequent period of extended operation are evaluated for changes in fracture toughness. RV materials that are not traditionally plant-limiting because of low levels of neutron radiation must now be evaluated to determine the accumulated fluence at the end of subsequent period of extended operation. Therefore, fast neutron (E > 1.0 MeV) fluence calculations were performed for the RV to determine where it will exceed a fast neutron (E > 1.0 MeV) fluence of 1.0×10^{17} n/cm^2 at the end of the subsequent period of extended operation. The materials that exceed the 1.0×10^{17} n/cm^2 fast neutron (E > 1.0 MeV) fluence threshold and were not evaluated in past analyses of record as part of the traditional beltline, are referred to as extended beltline materials and are evaluated to determine the effect of neutron irradiation embrittlement during subsequent period of extended operation.

Transport calculations were carried out using the three-dimensional discrete ordinates code RAPTOR-M3G and the BUGLE-96 cross-section library in accordance with the methodology described in WCAP-18124-NP-A, "Fluence Determination with RAPTOR-M3G and FERRET"

(Reference 4.8-33) and WCAP-18124-NP-A Supplement 1-NP-A, “Fluence Determination with RAPTOR-M3G and FERRET – Supplement for Extended Beltline Materials” (Reference 4.8-34). The BUGLE-96 library provides a 67-group coupled neutron-gamma ray cross-section data set produced specifically for light water reactor applications. In these analyses, anisotropic scattering was treated with a P_3 Legendre expansion and the angular discretization was modeled with an S_{16} order of angular quadrature. Energy- and space-dependent core power distributions, as well as system operating temperatures, were treated on a fuel-cycle-specific basis.

The calculations for fuel Cycles 1 through 26 determine the neutron exposure of the RV and surveillance capsules based on completed fuel cycles. Cycle 27 was completed in April 2023. The projections for Cycle 28 and beyond, up to and including the end of the period of extended operation (56 EFPY) and the end of the subsequent period of extended operation (72 EFPY), are based on the average core power distributions and reactor operating conditions of Cycles 25, 26, and 27 and are determined both with and without a 10% positive bias on the peripheral and re-entrant corner assembly relative powers.

Table 4.2.1-1 presents the fast neutron (E > 1.0 MeV) fluence results for the applicable portions of the RV with and without the 10% bias from the neutron transport analyses. Only those results with the 10% bias are used in the USE, PTS, and ART calculations. The outlet nozzles and inlet nozzles have fast neutron (E > 1.0 MeV) fluence greater than 1.0×10^{17} n/cm^2 at the lowest extent of the nozzle forging to nozzle shell weld at 72 EFPY. All materials located above the nozzles will remain below 1.0×10^{17} n/cm^2 through 72 EFPY. The lower shell to lower RV head circumferential weld, and all materials below it, will remain below 1.0×10^{17} n/cm^2 through the subsequent period of extended operation. Figure 4.2.2-1 shows the axial boundary of the 1.0×10^{17} n/cm^2 fluence threshold (at 54 EFPY and 72 EFPY) and as a function of azimuthal position.

As illustrated by the following conclusions, extended beltline fluence inputs can increase significantly before an extended beltline material would become more controlling than the limiting beltline material for each of the RV integrity evaluations completed for the subsequent period of extended operation, as documented in WCAP-18728-NP, “V.C. Summer Nuclear Station Unit 1 Subsequent License Renewal: Evaluation of Reactor Vessel Integrity Time-Limited Aging Analysis” (Reference 4.8-30):

- The limiting RV extended beltline materials have ART values that are less than the limiting beltline material ART values used for P-T limit curve development. The fluence in the extended beltline region would need to more than double in order for an extended beltline material to become limiting.
- The nozzles will not be limiting with respect to the 10 CFR 50, Appendix G, P-T limit curves as long as the fluence at the nozzle corner remains less than 4.28×10^{17} n/cm^2. Currently, the 72 EFPY maximum fluence projection in this region is 3.10×10^{17} n/cm^2, conservatively taken at the lowest extent of the inlet nozzle welds.

- A margin of 25.3°F exists between the limiting extended beltline RT_{PTS} value and the limiting beltline material RT_{PTS} value. An additional margin of greater than 117.5°F exists to the RT_{PTS} screening criteria. A fluence increase of greater than 3 times would be required for an extended beltline material to become limiting in terms of RT_{PTS} compared to the beltline materials.
- The projected fluence values of the extended beltline base metals and welds could increase by more than two orders of magnitude before the limiting USE value would drop below 50 ft-lb for the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The fluence analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii). The results have been used as inputs in the RV neutron embrittlement TLAA evaluations in Section 4.2.2 through Section 4.2.6.

Table 4.2.1-1 Maximum Fast Neutron (E > 1.0 MeV) Fluence Experienced by the Reactor Vessel Materials in the Beltline and Extended Beltline Regions

Projections with no bias on the peripheral and re-entrant corner assembly relative powers			
Location	**Material**	**Fluence (n/cm^2)**	
		54 EFPY(d)	**72 EFPY**
Extended Beltline Materials	Inlet Nozzle to Nozzle Shell Weld (lowest extent)(b)	2.24×10^{17}	2.99×10^{17}
	Inlet Nozzle Postulated 1/4T Flaw(b)	2.68×10^{16}	3.58×10^{16}(c)
	Outlet Nozzle to Nozzle Shell Weld(b) (lowest extent)	9.55×10^{16}	1.27×10^{17}
	Outlet Nozzle Postulated 1/4T Flaw(b)	1.37×10^{16}	1.82×10^{16}(c)
	Upper Shell(a)	2.89×10^{18}	3.83×10^{18}
	Upper-to-Intermediate Shell Circumferential Weld	3.07×10^{18}	4.07×10^{18}
Beltline Materials	Intermediate Shell	6.51×10^{19}	8.62×10^{19}
	Intermediate Shell Longitudinal Weld – 45°/225°	2.19×10^{19}	2.89×10^{19}
	Intermediate-to-Lower Shell Circumferential Weld	6.51×10^{19}	8.62×10^{19}
	Lower Shell	6.52×10^{19}	8.64×10^{19}
	Lower Shell Longitudinal Weld – 135°/315°	2.22×10^{19}	2.93×10^{19}
Outside of Beltline Region	Lower Shell to Bottom Head Circumferential Weld(b)	7.43×10^{15}	9.86×10^{15}

Table 4.2.1-1 Maximum Fast Neutron (E > 1.0 MeV) Fluence Experienced by the Reactor Vessel Materials in the Beltline and Extended Beltline Regions

Projections with a +10% bias on the peripheral and re-entrant corner assembly relative powers			
Location	**Material**	**Fluence (n/cm^2)**	
		54 EFPY[(d)]	**72 EFPY**
Extended Beltline Materials	Inlet Nozzle to Upper Shell Weld (lowest extent)[(b)]	2.30×10^{17}	3.10×10^{17}
	Inlet Nozzle Postulated 1/4T Flaw[(b)]	2.74×10^{16}	3.69×10^{16}[(c)]
	Outlet Nozzle to Upper Shell Weld (lowest extent)[(b)]	9.79×10^{16}	1.32×10^{17}
	Outlet Nozzle Postulated ¼T Flaw[(b)]	1.40×10^{16}	1.88×10^{16}[(c)]
	Upper Shell[(a)]	2.98×10^{18}	4.00×10^{18}
	Upper-to-Intermediate Shell Circumferential Weld	3.16×10^{18}	4.25×10^{18}
Beltline Materials	Intermediate Shell	6.73×10^{19}	9.04×10^{19}
	Intermediate Shell Longitudinal Weld – 45°/225°	2.26×10^{19}	3.03×10^{19}
	Intermediate-to-Lower Shell Circumferential Weld	6.73×10^{19}	9.04×10^{19}
	Lower Shell	6.74×10^{19}	9.06×10^{19}
	Lower Shell Longitudinal Weld – 135°/315°	2.30×10^{19}	3.08×10^{19}
Outside of beltline region	Lower Shell to Bottom Head Circumferential Weld[(b)]	7.67×10^{15}	1.03×10^{16}

Footnote(s):

(a) Exposure values for the upper shell longitudinal welds are bounded by the exposure values for the upper shell.

(b) Maximum exposure values occur at the RV outer radius.

(c) While the fluence at this location is less than 1×10^{17} n/cm^2, it is identified as extended beltline since portions of the nozzle exceed the criterion.

(d) 54 EFPY is derived from 33.75 plus 20 rounded to 54 EFPY.

4.2.2 UPPER-SHELF ENERGY

TLAA Description:

Upper-shelf energy (USE) is the parameter used to indicate the toughness of a material at elevated temperature. There are two sets of rules that govern USE acceptance criteria. 10 CFR 50, Appendix G, Paragraph IV.A.1.a, states that RV beltline materials must have Charpy USE of no less than 75 ft-lbs initially, and must maintain Charpy USE throughout the life of the RV of no less than 50 ft-lbs, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by ASME Code, Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” (Reference 4.8-6), Appendix G, “Fracture Toughness Criteria for Protection Against Failure.” The material outside the beltline was originally qualified using the requirements of the ASME Code, Section III, in effect at the time of the design and fabrication of the RV. All non-beltline materials expected to exceed $1x10^{17}$ n/cm^2 are referred to as extended beltline and must have the USE evaluated, include the embrittlement effects. All beltline and extended beltline USE analyses are identified as a TLAA requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

Per NRC Regulatory Guide (RG) 1.99, “Radiation Embrittlement of Reactor Vessel Materials,” (Reference 4.8-7) the Charpy USE should be assumed to decrease as a function of fluence according to Figure 2 of RG 1.99, which provides percent decrease in USE as a function of 1/4T fluence and the copper content for plates and welds, when credible surveillance data is not available. If credible surveillance data is available, the decrease in USE may be obtained by plotting the reduced plant-specific surveillance data on Figure 2 of Regulatory Guide 1.99 and fitting the data with a line drawn parallel to the existing lines as the upper bound of all of the data. The 1/4T fluence at 72 EFPY is used to determine the reduction in the initial USE.

As documented in WCAP-18728-NP, the materials projected to exceed 1.0 x 10^{17} n/cm^2 (E > 1.0 MeV) at 72 EFPY are evaluated to determine their impact on USE during the proposed subsequent period of extended operation. The shell plates and welds corresponding to the inlet and outlet nozzles are predicted to experience neutron fluence greater than 1.0 x 10^{17} n/cm^2 at the end of the subsequent period of extended operation. The extended beltline materials include two (2) nozzle shell plates, three (3) inlet nozzles, three (3) outlet nozzles, three (3) inlet nozzle to upper-shell welds, three (3) outlet nozzle to upper-shell welds, the nozzle shell longitudinal welds, and the nozzle to intermediate shell circumferential weld. (Note: nozzle-shell and upper-shell refer to the same component and are used interchangeably.) The corner region of the three (3) outlet nozzles and three (3) inlet nozzles are projected to experience neutron fluence less than 1.0 X 10^{17} n/cm^2 at the end of the subsequent period of extended operation.

The identification of the RV plate and weld materials is shown in Table 4.2.2-1. The material property inputs used for the RV integrity evaluations are described in this section. The initial material properties were updated from previous RV integrity evaluations per PWROG-21037-NP, "Determination of Unirradiated RT_{NDT} and Upper-Shelf Energy Values of the V.C. Summer Unit 1 Reactor Vessel Materials," and the fluence values were updated per WCAP-18709-NP.

The requirements on USE are included in 10 CFR 50, Appendix G which requires utilities to submit an analysis at least 3 years prior to the time that the USE of any RV material is predicted to drop below 50 ft-lb, as measured by Charpy V-notch specimen testing.

Two methods can be used to predict the decrease in USE with irradiation, depending on the availability of credible surveillance capsule data as defined in RG 1.99, Revision 2. For RV beltline materials that are not in the surveillance program or have non-credible data, the Charpy USE (Position 1.2) is assumed to decrease as a function of fluence and copper content, as indicated in RG 1.99, Revision 2. When two or more credible surveillance sets become available from the reactor, they may be used to determine the Charpy USE of the surveillance material. The surveillance data are then used in conjunction with Regulatory Guide 1.99, Revision 2 to predict the change in USE (Position 2.2) of the RV material due to irradiation. Per Regulatory Guide 1.99, Revision 2, when credible data exist, the Position 2.2 projected USE value should be used in preference to the Position 1.2 projected USE value. Note, if data from the surveillance materials is determined to be non-credible for determination of ΔRT_{NDT} by Credibility Criterion 3 of Regulatory Guide 1.99, Revision 2, then "they may be credible for determining decrease in upper-shelf energy if the upper shelf can be clearly determined, following the definition given in ASTM E185-82."

The 72 EFPY Position 1.2 USE values of the RV materials can be predicted using the corresponding 1/4T fluence projections, the copper content of the materials, and Figure 2 in RG 1.99, Revision 2.

The predicted Position 2.2 USE values are determined for the RV materials that are contained in the surveillance program by using the reduced plant-specific surveillance data along with the corresponding fluence projection (1/4T for beltline materials). The reduced plant-specific surveillance data was obtained from WCAP-16298-NP. The surveillance data was plotted in RG 1.99, Revision 2, Figure 2. This data was fitted by drawing a line parallel to the existing lines as the upper bound of the surveillance data. These reduced lines were used instead of the existing lines to determine the Position 2.2 end of the subsequent period of extended operation USE values.

The projected USE values were calculated to determine if the beltline and extended beltline materials remain above the 50 ft-lb criterion at 72 EFPY. The projected USE values for the inlet and outlet nozzle forgings were conservatively calculated using the maximum fluence values corresponding to the lowest extent of the nozzle to shell welds. These calculations are summarized in Table 4.2.2-2.

As shown in Table 4.2.2-2, the RV materials are projected to remain at or above the USE screening criterion value of 50 ft-lb at 72 EFPY. The limiting USE value at 72 EFPY is 63 ft-lb corresponds to Intermediate Shell 11-1 using Position 2.2. The surveillance data for Intermediate Shell 11-1 is used despite it being determined to be non-credible, as the upper shelf can be clearly determined for the surveillance specimens (WCAP-16298-NP). Note, both the Position 1.2 and 2.2 results for Intermediate Shell 11-1 remain above 50 ft-lb.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The USE analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

Figure 4.2.2-1 Axial Boundary of the 1.0 x 10^{17} n/cm^2 Fast Neutron (E > 1.0 MeV) Fluence Threshold in the +Z Direction at 33.75 (end of Cycle 27), 54, and 72 EFPY

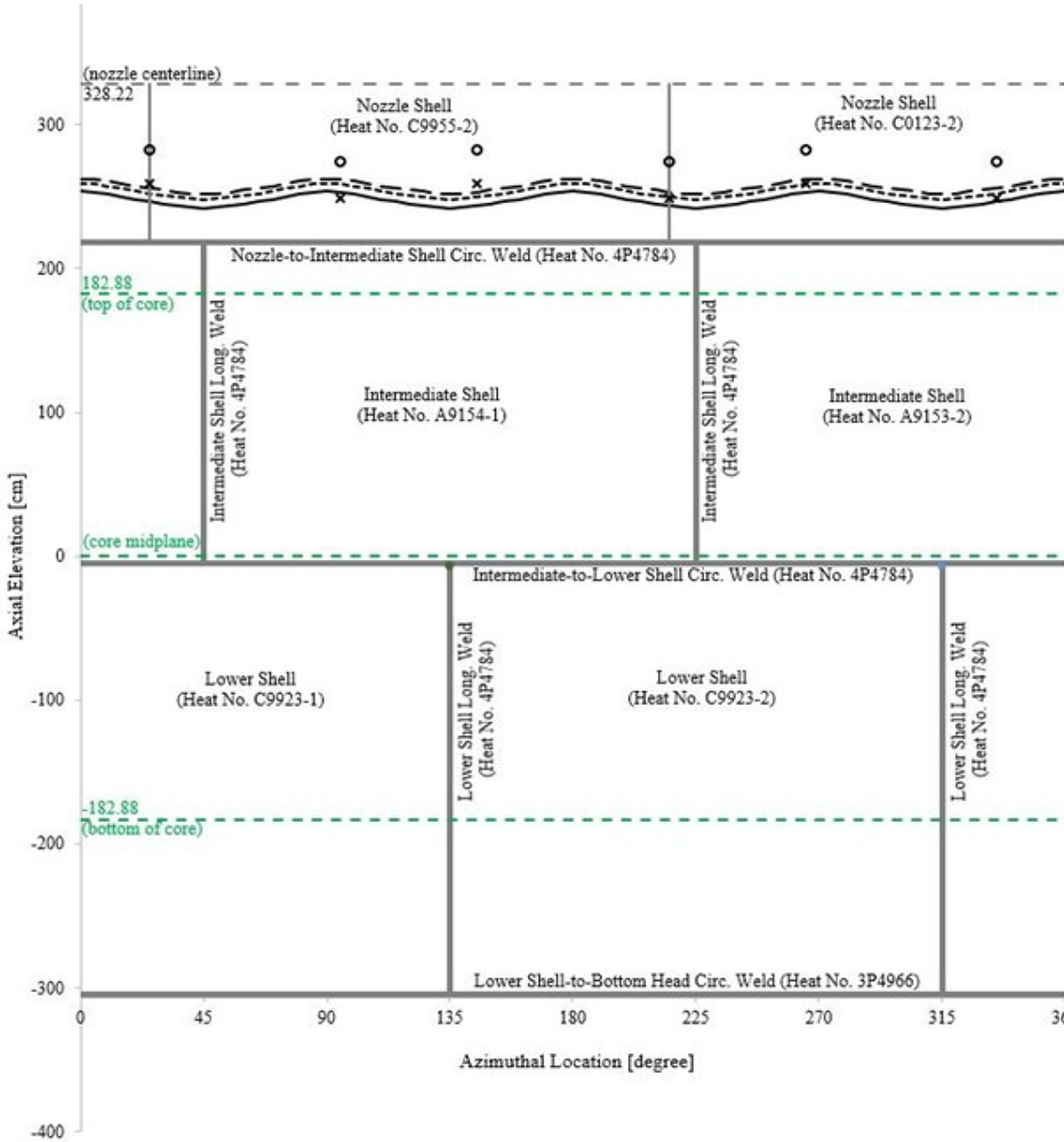

Figure 4.2.2-2 Reactor Vessel Schematic

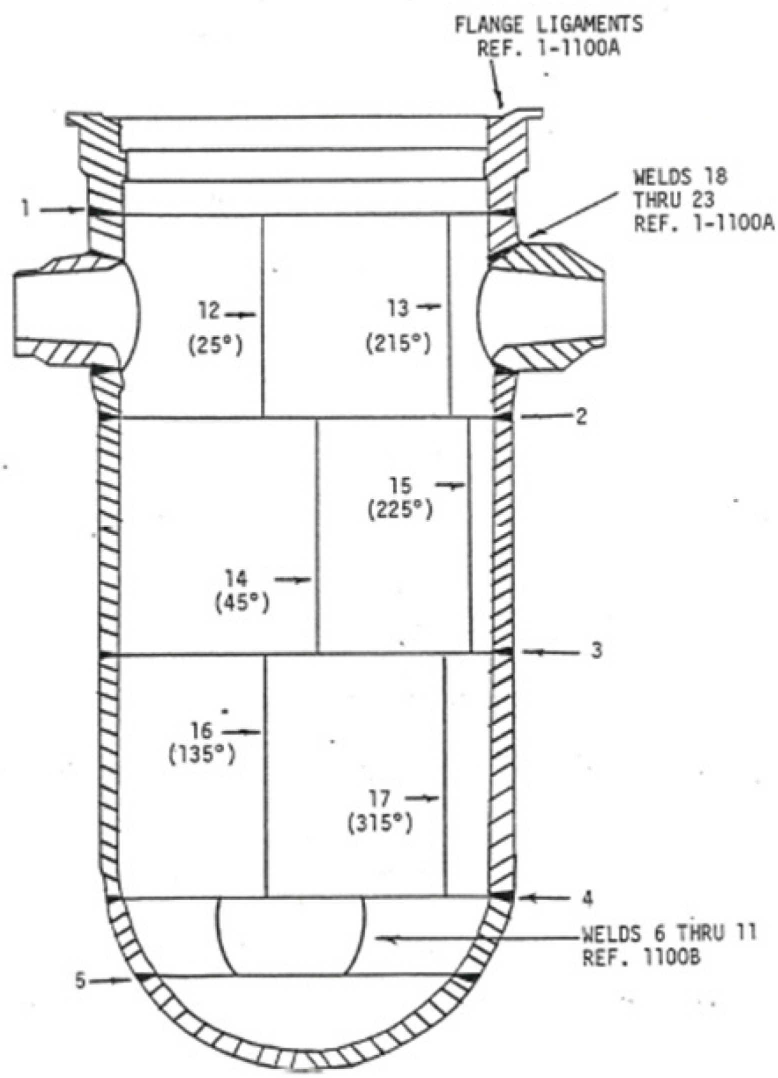

Table 4.2.2-1 Best--Estimate Cu and Ni Weight Percent Values, Initial RT_{NDT} Values, and Initial USE Values for the RPV Beltline and Extended Beltline Materials[a]

Material Identification	Wt.% Cu	Wt.% Ni	Initial RT_{NDT} (°F)	Unirradiated USE (ft-lb)
Beltline				
Intermediate Shell 11-1 (Heat # A9154-1)	0.10	0.51	21	76
Intermediate Shell 11-2 (Heat # A9153-2)	0.09	0.45	-20	107
Lower Shell 10-1 (Heat # C9923-1)	0.08	0.41	5	106
Lower Shell 10-2 (Heat # C9923-2)	0.08	0.41	4	92
Intermediate Shell Long. Weld Seams BC & BD (Heat # 4P4784, Flux Type Linde 124, Lot # 3930)	0.05	0.91	-49	86
Intermediate to Lower Shell Circ. Weld Seam AB (Heat # 4P4784, Flux Type Linde 124, Lot # 3930)				
Lower Shell Long. Weld Seams BA & BB (Heat # 4P4784, Flux Type Linde 124, Lot # 3930)				
Extended Beltline				
Nozzle Shell 12-1 (Heat # C9955-2)	0.13	0.57	9	101
Nozzle Shell 12-2 (Heat # C0123-2)	0.12	0.58	15	91
Inlet Nozzle 436B-1 (Heat # Q2Q41W)	0.127[b]	0.76	-20	152
Inlet Nozzle 436B-2 (Heat # Q2Q39W)	0.127[b]	0.82	0	115
Inlet Nozzle 436B-3 (Heat # Q2Q39W)	0.127[b]	0.82	-20	138
Outlet Nozzle 437B-1 (Heat # Q2Q40)	0.127[b]	0.85	-10	159
Outlet Nozzle 437B-2 (Heat # Q2Q40W)	0.127[b]	0.80	-10	165
Outlet Nozzle 437B-3 (Heat # Q2Q44W)	0.127[b]	0.78	0	155

Table 4.2.2-1 Best--Estimate Cu and Ni Weight Percent Values, Initial RT_{NDT} Values, and Initial USE Values for the RPV Beltline and Extended Beltline Materials[a]

Material Identification	Wt.% Cu	Wt.% Ni	Initial RT_{NDT} (°F)	Unirradiated USE (ft-lb)
Extended Beltline (continued)				
Nozzle to Intermediate Shell Circ. Weld Seam AC (Heat # 4P4784, Flux Type Linde 124, Lot # 3930)	0.05	0.91	-49	86
Nozzle Shell Long. Weld Seams BE and BF[c]	0.06[c]	1.01[c]	10[c]	80[c]
Inlet/Outlet Nozzle Forgings to Nozzle Shell Weld Seams 15A/B/C & 16A/B/C[c]				
Surveillance Weld (Heat # 4P4784, Flux Type Linde 124, Lot # 3930)	0.04	0.95	-	-

Footnote(s):

(a) All values are based on information extracted from the certified material test reports (CMTRs) and/or vessel fabrication records, unless noted otherwise.

(b) Generic value for SA-508 Class 2 nozzle forgings.

(c) The specific heat number used in weld seams could not be identified. To address these situations, values were determined based on a review of all weld heats used in the fabrication of the RV.

Table 4.2.2-2 Predicted USE Values at 72 EFPY for the Beltline and Extended Beltline Materials

Material	Wt% Cu[(a)]	1/4T Fluence ($x 10^{19}$ n/cm^2, E > 1.0 MeV)[(b)]	Unirradiated USE (ft-lb)[(a)]	Projected USE Decrease (%)	Projected USE (ft-lb)
Position 1.2[(c)]					
Intermediate Shell 11-1 (Heat # A9154-1)	0.10	5.68	76	29	54
Intermediate Shell 11-2 (Heat # A9153-2)	0.09	5.68	107	29	76
Lower Shell 10-1 (Heat # C9923-1)	0.08	5.69	106	29	75
Lower Shell 10-2 (Heat # C9923-2)	0.08	5.69	92	29	65
Intermediate Shell Long. Weld Seams BC & BD (Heat # 4P4784)	0.05	1.90	86	22	67
Intermediate to Lower Shell Circ. Weld Seam AB (Heat # 4P4784)	0.05	5.68	86	29	61
Lower Shell Long. Weld BA & BB (Heat # 4P4784)	0.05	1.93	86	23	66
Nozzle Shell 12-1 (Heat # C9955-2)	0.13	0.251	101	17	84
Nozzle Shell 12-2 (Heat # C0123-2)	0.12	0.251	91	16	76
Inlet Nozzle 436B-1 (Heat # Q2Q41W)	0.127	0.0310[(d)]	152	10	137
Inlet Nozzle 436B-2 (Heat # Q2Q39W)	0.127	0.0310[(d)]	115	10	104
Inlet Nozzle 436B-3 (Heat # Q2Q39W)	0.127	0.0310[(d)]	138	10	124
Outlet Nozzle 437B-1 (Heat # Q2Q40)	0.127	0.0132[(d)]	159	9	145

Table 4.2.2-2 Predicted USE Values at 72 EFPY for the Beltline and Extended Beltline Materials

Material	Wt% Cu[a]	1/4T Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[b]	Unirradiated USE (ft-lb)[a]	Projected USE Decrease (%)	Projected USE (ft-lb)
Position 1.2[c] (continued)					
Outlet Nozzle 437B-2 (Heat # Q2Q40W)	0.127	0.0132[d]	165	9	150
Outlet Nozzle 437B-3 (Heat # Q2Q44W)	0.127	0.0132[d]	155	9	141
Nozzle to Intermediate Shell Circ. Weld Seam AC (Heat # 4P4784)	0.05	0.267	86	14	74
Nozzle Shell Long. Weld Seams BE & BF	0.06	0.251	80	15	68
Inlet/Outlet Nozzle Forgings to Nozzle Shell Weld Seams 15A/B/C & 16A/B/C	0.06	0.0310[d]	80	9	73
Position 2.2[c]					
Intermediate Shell 11-1 (Heat #A9154-1)	0.10	5.68	76	17	63
Intermediate Shell Long. Weld Seams BC & BD (Heat # 4P4784)	0.05	1.90	86	9	78
Intermediate to Lower Shell Circ. Weld Seam AB (Heat # 4P4784)	0.05	5.68	86	12	76
Lower Shell Long. Weld Seams BA & BB (Heat # 4P4784)	0.05	1.93	86	9	78
Nozzle to Intermediate Shell Circ. Weld Seam AC (Heat # 4P4784)	0.05	0.267	86	6	81

Footnote(s):

(a) Copper weight percent values and unirradiated USE values. If the base metal or weld Cu weight percentages were below the minimum value presented in Figure 2 of RG 1.99 (0.1 for base metal and 0.05 for welds), then the Cu weight percentages were conservatively rounded up to the minimum value for projected USE decrease determination.

(b) All fluence values are based on the projections which include the 10% bias on the core periphery. Fluence values above 1 x 10^{17} n/cm^2 (E > 1.0 MeV) but below 2 x 10^{17} n/cm^2 (E > 1.0 MeV) were rounded to 2 x 10^{17} n/cm^2 (E > 1.0 MeV) when determining the percent decrease because 2 x 10^{17} n/cm^2 is the lowest fluence displayed in Figure 2 of RG 1.99.

(c) Position 1.2 percentage USE decrease values were calculated by plotting the 1/4T fluence values on RG 1.99, Figure 2 and using the material-specific Cu wt.% values. The percent-loss lines were extended into the low fluence area of RG 1.99, Figure 2 (i.e., below 10^{18} n/cm^2) in order to determine the USE percent decrease, as needed. Position 2.2 percentage USE decrease values were determined by drawing an upper-bound line parallel to the existing RG 1.99, Figure 2 lines through the applicable surveillance data points. These results should be used in preference to the existing graph lines for determining the decrease in USE, because the surveillance data is credible.

(d) Values are the maximum fluence values instead of the 1/4T fluence values.

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4.2.3 PRESSURIZED THERMAL SHOCK

TLAA Description:

A limiting condition on RV integrity known as Pressurized Thermal Shock (PTS) may occur during a severe system transient such as a small-break loss-of-coolant accident (LOCA) or steam line break. Such transients may challenge the integrity of the RV under the following conditions: severe over-cooling of the inside surface of the RV wall followed by re-pressurization, significant degradation of RV material toughness caused by radiation embrittlement and the presence of a critical-size defect anywhere within the RV wall.

10 CFR 50.61(b)(1) provides rules for protection against PTS events for pressurized water reactors (PWRs). Licensees are required to perform an updated assessment of the projected values of the PTS reference temperature (RT_{PTS}) whenever there is a significant change in projected values of RT_{PTS} or upon a request for a change in the expiration date for operation of the facility. The current analysis evaluated for 56 EFPY fluence values predicted for 60 years of operation are TLAAs requiring evaluation for 80 years since a change in the operating license term of the facility is being requested.

TLAA Evaluation:

10 CFR 50.61(c) provides two methods for determining RT_{PTS}. These methods are also described as Positions 1 and 2 in RG 1.99, Revision 2. Position 1 applies for material without credible surveillance data available and Position 2 is used for material with two or more credible surveillance data sets available. The RT_{PTS} values are calculated for both Positions 1 and 2 by following the guidance in RG 1.99, Revision 2 (Sections 1.1 and 2.1, respectively), using the copper and nickel content of the beltline materials, and subsequent period of extended operation fluence projections.

These accepted methods were used with the surface fluence, (i.e., clad / base metal interface) values above to calculate the following RT_{PTS} values for the RV materials at 72 EFPY. Only the fluence results with the 10% bias are used in the PTS evaluation. The subsequent period of extended operation RT_{PTS} calculations are summarized in Table 4.2.3-1.

PWROG-21037-NP summarizes the results and methodologies used in the determination of the unirradiated / initial nil-ductility transition temperature ($RT_{NDT(u)}$ or initial RT_{NDT}) for the RV materials. WCAP-18728-NP provides the RT_{PTS} calculations for the beltline and extended beltline materials.10 CFR 50.61(b)(2) establishes screening criteria for RT_{PTS} as 270°F for plates, forgings, and longitudinal welds and 300°F for circumferential welds.

The beltline and extended beltline materials in the RV are below the RT_{PTS} screening criteria values of 270°F for base metal and/or longitudinal welds, and 300°F for circumferentially oriented welds through the subsequent period of extended operation (72 EFPY). These RT_{PTS} values are based on the revised initial RT_{NDT} developed using ASME Section III methodologies. Limiting fluence values corresponding to the lowest extent of the nozzle welds were used to calculate the RT_{PTS} values for both the nozzle welds and nozzle forgings.

The limiting RT_{PTS} value for base metal and longitudinal welds at 72 EFPY is 152.5°F (Table 4.2.3-1), which corresponds to Intermediate Shell 11-1 based on Regulatory Guide 1.99, Position 1.1. There is surveillance data available for this material that indicated the ΔRT_{NDT} will be less than that predicted by Regulatory Guide 1.99, Position 1.1. However, because the surveillance data was determined to be non-conservative, it is not credited for this application. The limiting RT_{PTS} value for circumferentially oriented welds at 72 EFPY is 42.5°F (Table 4.2.3-1), which corresponds to the Intermediate to Lower Shell Circumferential Weld Heat # 4P4784 based on Regulatory Guide 1.99, Position 2.1 with credible surveillance data. The credible surveillance data for Heat # 4P4784 supersedes the higher RT_{PTS} based on Regulatory Guide 1.99, Position 1.1. Both the Position 1.1 and 2.1 remain below 300°F.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The PTS analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

Table 4.2.3-1 RT_{PTS} Calculations at 72 EFPY

Material	Heat Number	Flux Type (Lot)	RG 1.99, Rev. 2 Position	CF	Surf. Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)	Surf. FF[a]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)[cb]	M (°F)	RT_{PTS} (°F)
Beltline Materials												
Intermediate Shell 11-1	A9154-1	-	1.1	65.0	9.04	1.501	21	97.5	0.0	17.0	34.0	152.5
Using non-credible surveillance data[c]			2.1	43.5	9.04	1.501	21	65.3	0.0	17.0	34.0	120.3
Intermediate Shell 11-2	A9153-2	-	1.1	58.0	9.04	1.501	-20	87.0	0.0	17.0	34.0	101.0
Lower Shell 10-1	C9923-1	-	1.1	51.0	9.06	1.501	5	76.6	0.0	17.0	34.0	115.6
Lower Shell 10-2	C9923-2	-	1.1	51.0	9.06	1.501	4	76.6	0.0	17.0	34.0	114.6
Intermediate Shell Long. Weld Seams BC & BD	4P4784	Linde 124 (3930)	1.1	68.0	3.03	1.293	-49	87.9	0.0	28.0	56.0	94.9
Using credible surveillance data[c]			2.1	42.3	3.03	1.293	-49	54.7	0.0	14.0	28.0	33.7
Intermediate to Lower Shell Circ. Weld Seam AB	4P4784	Linde 124 (3930)	1.1	68.0	9.04	1.501	-49	102.0	0.0	28.0	56.0	109.0
Using credible surveillance data[c]			2.1	42.3	9.04	1.501	-49	63.5	0.0	14.0	28.0	42.5
Lower Shell Long. Weld Seams BA & BB	4P4784	Linde 124 (3930)	1.1	68.0	3.08	1.297	-49	88.2	0.0	28.0	56.0	95.2
Using credible surveillance data[c]			2.1	42.3	3.08	1.297	-49	54.9	0.0	14.0	28.0	33.9

Table 4.2.3-1 RT_{PTS} Calculations at 72 EFPY

Material	Heat Number	Flux Type (Lot)	RG 1.99, Rev. 2 Position	CF	Surf. Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)	Surf. FF[a]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ I (°F)	σ_Δ (°F)[cb]	M (°F)	RT_{PTS} (°F)
Extended Beltline Materials												
Nozzle Shell 12-1	C9955-2	-	1.1	90.1	0.400	0.746	9	67.2	0.0	17.0	34.0	110.2
Nozzle Shell 12-2	C0123-2	-	1.1	82.6	0.400	0.746	15	61.6	0.0	17.0	34.0	110.6
Inlet Nozzle 436B-1	Q2Q41W	-	1.1	92.1	0.0310	0.224	-20	20.6	0.0	10.3	20.6	21.2
Inlet Nozzle 436B-2	Q2Q39W	-	1.1	93.0	0.0310	0.224	0	20.8	0.0	10.4	20.8	41.6
Inlet Nozzle 436B-3	Q2Q39W	-	1.1	93.0	0.0310	0.224	-20	20.8	0.0	10.4	20.8	21.6
Outlet Nozzle 437B-1	Q2Q40	-	1.1	93.0	0.0132	0.132	-10	12.3	0.0	6.1	12.3	14.5
Outlet Nozzle 437B-2	Q2Q40W	-	1.1	93.0	0.0132	0.132	-10	12.3	0.0	6.1	12.3	14.5
Outlet Nozzle 437B-3	Q2Q44W	-	1.1	92.6	0.0132	0.132	0	12.2	0.0	6.1	12.2	24.4
Nozzle to Intermediate Shell Circ. Weld Seam AC	4P4784	Linde 124 (3930)	1.1	68.0	0.425	0.762	-49	51.8	0.0	25.9	51.8	54.7

Table 4.2.3-1 RT_{PTS} Calculations at 72 EFPY

Material	Heat Number	Flux Type (Lot)	RG 1.99, Rev. 2 Position	CF	Surf. Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)	Surf. FF[a]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)[cb]	M (°F)	RT_{PTS} (°F)
Using credible surveillance data[c]			2.1	42.3	0.425	0.762	-49	32.2	0.0	14.0	28.0	11.2
Nozzle Shell Long. Weld Seams BE and BF	-	-	1.1	82.0	0.400	0.762	10	61.2	0.0	28.0	56.0	127.2
Inlet/Outlet Nozzle Forgings to Nozzle Shell Weld Seams 15A/B/C & 16A/B/C	-	-	1.1	82.0	0.0310	0.224	10	18.4	0.0	9.2	18.4	46.7

Footnote(s)

(a) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(b) Per 10 CFR 50.61, the base metal σ_Δ = 17°F when surveillance data are non-credible or not used to determine the CF, and the base metal σ_Δ = 8.5°F when credible surveillance data are used. Also, per 10 CFR 50.61, the weld metal σ_Δ = 28°F when surveillance data are non-credible or not used to determine the CF, and the weld metal σ_Δ = 14°F when credible surveillance data are used. However, σ_Δ need not exceed 0.5*ΔRT_{NDT} for either base metals or welds, with or without surveillance data.

(c) The credibility evaluation for the surveillance data determined that the surveillance data for the Intermediate Shell 11-1 (Heat # A9154-1) was deemed non-credible and the Surveillance Weld (Heat # 4P4784) was deemed credible.

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4.2.4 ADJUSTED REFERENCE TEMPERATURE

TLAA Description:

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. Regulatory Guide (RG) 1.99, Revision 2, provides the methodology for determining the ART of the limiting material. The initial RT_{NDT} is the temperature at which a non-irradiated metal (ferritic steel) changes in fracture characteristics from ductile to brittle behavior. Neutron fluence increases the RT_{NDT} beyond its initial value.

RT_{NDT} was evaluated in accordance with PWROG-21037-NP, which includes the generally accepted techniques outlined in:

- ASME Code, Section III, Paragraph NB 2331, "Material for Vessel"
- Branch Technical Position 5-3, "Fracture Toughness Requirements" (Reference 4.8-9)

10 CFR 50, Appendix G, defines the fracture toughness requirements for the RV. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lbs index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) means that higher temperatures are required for the material to continue to act in a ductile manner. The ART is defined as the sum of the initial (RT_{NDT}), the mean value of the adjustment in RT caused by irradiation (ΔRT_{NDT}), and a margin (M) term.

Since the ΔRT_{NDT} value is a function of fluence associated with the 60-year licensed operating period, these ART calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

TLAA Evaluation:

RT_{NDT} increases as the material is exposed to fast-neutron irradiation; therefore, to find the most limiting RT_{NDT} at any time period in the reactor's life, ΔRT_{NDT} due to the radiation exposure associated with that time period must be added to the initial RT_{NDT}. Using the ART values, P-T limit curves are determined in accordance with the requirements of 10 CFR Part 50, Appendix G, as augmented by ASME Code, Section XI, Appendix G.

The P-T limit curves for normal heatup and cooldown of the primary reactor coolant system were previously developed in WCAP-16305-NP. The existing P-T limit curves are based on the limiting beltline material ART values, which are influenced by both the fluence and the initial material properties of that material. Since the development of the curves, the fluence values and initial material properties used to calculate ART values have been updated and an applicability check of the current P-T limit curves is appropriate.

To confirm whether the current P-T limit curves will remain valid through the period of extended operation and through the subsequent period of extended operation, WCAP-18728-NP computed updated ART values for the limiting materials to account for updated 56 EFPY and 72 EFPY fluence values, updated chemistry factor values, and updated initial RT_{NDT} values. Regulatory Guide 1.99, Revision 2 methodology was used along with the surface fluence of Section 4.2 to calculate ART values, which are summarized in Table 4.2.4-1 through Table 4.2.4-6. Note, the inlet/outlet nozzle forgings and associated welds neglect attenuation through the material; thus, ART calculations are only needed at one location (i.e., the location of maximum fluence). The impact of the ART values on the P-T curves applicability is discussed in Section 4.2.5.

ART projections contained herein are based on those projected fluence values with a 10% bias on the peripheral and re-entrant corner assembly relative powers.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The ART analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii). They may be used as inputs to 72 EFPY P-T limits for the subsequent period of extended operation.

Table 4.2.4-1 Calculation of the ART Values at the 1/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at the End of Period of Extended Operation (56 EFPY)[(a)]

Material	RG 1.99, Rev. 2 Position	CF	Surface Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)(g)]	1/4T Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)]	1/4T FF[(b)]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)[(c)]	M (°F)	ART (°F)
Beltline Materials											
Intermediate Shell 11-1 (Heat # A9154-1)	1.1	65.0	6.99	4.39	1.376	21	89.4	0.0	17.0	34.0	144.4
Using non-credible surveillance data[(d)]	2.1	43.5	6.99	4.39	1.376	21	59.9	0.0	17.0	34.0	114.9
Intermediate Shell 11-2 (Heat # A9153-2)	1.1	58.0	6.99	4.39	1.376	-20	79.8	0.0	17.0	34.0	93.8
Lower Shell 10-1 (Heat # C9923-1)	1.1	51.0	7.00	4.40	1.376	5	70.2	0.0	17.0	34.0	109.2
Lower Shell 10-2 (Heat # C9923-2)	1.1	51.0	7.00	4.40	1.376	4	70.2	0.0	17.0	34.0	108.2
Intermediate Shell Long. Weld Seams BC & BD Heat # 4P4784)	1.1	68.0	2.35	1.48	1.108	-49	75.3	0.0	28.0	56.0	82.3
Using credible surveillance data[(d)]	2.1	42.3	2.35	1.48	1.108	-49	46.9	0.0	14.0	28.0	25.9
Intermediate to Lower Shell Circ. Weld Seam AB (Heat # 4P4784)	1.1	68.0	6.99	4.39	1.376	-49	93.6	0.0	28.0	56.0	100.6

Table 4.2.4-1 Calculation of the ART Values at the 1/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at the End of Period of Extended Operation (56 EFPY)[(a)]

Material	RG 1.99, Rev. 2 Position	CF	Surface Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)(g)]	1/4T Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)]	1/4T FF[(b)]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)[(c)]	M (°F)	ART (°F)
Using credible surveillance data[(d)]	2.1	42.3	6.99	4.39	1.376	-49	58.2	0.0	14.0	28.0	37.2
Lower Shell Long. Weld Seams BA & BB (Heat # 4P4784)	1.1	68.0	2.39	1.50	1.112	-49	75.6	0.0	28.0	56.0	82.6
Using credible surveillance data[(d)]	2.1	42.3	2.39	1.50	1.112	-49	47.1	0.0	14.0	28.0	26.1
Extended Beltline Materials											
Nozzle Shell 12-1 (Heat # C9955-2)	1.1	90.1	0.309	0.194	0.563	9	50.7	0.0	17.0	34.0	93.7
Nozzle Shell 12-2 (Heat # C0123-2)	1.1	82.6	0.309	0.194	0.563	15	46.5	0.0	17.0	34.0	95.5
Nozzle to Intermediate Shell Circ. Weld Seam AC (Heat # 4P4784)	1.1	68.0	0.328	0.206	0.577	-49	39.2	0.0	19.6	39.2	29.4
Using credible surveillance data[(d)]	2.1	42.3	0.328	0.206	0.577	-49	24.4	0.0	12.2	24.4	-0.2
Nozzle Shell Long. Weld Seams BE and BF[(f)]	1.1	82.0	0.309	0.194	0.563	10	46.1	0.0	23.1	46.1	102.3

Footnote(s):

(a) The RG 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(c) Per the guidance of RG 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed 0.5*ΔRT_{NDT} for either base metals or welds, with or without surveillance data.

(d) The credibility evaluation for the surveillance data determined that the surveillance data for the Intermediate Shell 11-1 (Heat # A9154-1) is deemed non-credible and the Surveillance Weld (Heat # 4P4784) is deemed credible.

(e) The surface fluence values for the RV materials were interpolated from the data in Table 4.2.1-1. The 1/4T and 3/4T fluence values were calculated from the surface fluence, the RV beltline thickness (7.75 inches) and equation $f = f_{surf} * e^{-0.24\,(x)}$ from RG 1.99, Revision 2, where x = the depth into the RV wall (inches).

(f) Exposure values for the nozzle shell longitudinal welds are bounded by the exposure values for the nozzle shell.

(g) All fluence values are based on the projections which include the 10% bias on the core periphery.

Table 4.2.4-2 Calculation of the ART Values at the 3/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at the End of Period of Extended Operation (56 EFPY)[(a)]

Material	RG 1.99, Rev. 2 Position	CF	Surface Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)(g)]	3/4T Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)]	3/4T FF[(b)]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)[(c)]	M (°F)	ART (°F)
Beltline Materials											
Intermediate Shell 11-1 (Heat # A9154-1)	1.1	65.0	6.99	1.73	1.151	21	74.8	0.0	17.0	34.0	129.8
Using non-credible surveillance data[(d)]	2.1	43.5	6.99	1.73	1.151	21	50.1	0.0	17.0	34.0	105.1
Intermediate Shell 11-2 (Heat # A9153-2)	1.1	58.0	6.99	1.73	1.151	-20	66.8	0.0	17.0	34.0	80.8
Lower Shell 10-1 (Heat # C9923-1)	1.1	51.0	7.00	1.73	1.152	5	58.7	0.0	17.0	34.0	97.7
Lower Shell 10-2 (Heat # C9923-2)	1.1	51.0	7.00	1.73	1.152	4	58.7	0.0	17.0	34.0	96.7
Intermediate Shell Long. Weld Seams BC & BD (Heat # 4P4784)	1.1	68.0	2.35	0.582	0.849	-49	57.7	0.0	28.0	56.0	64.7
Using credible surveillance data[(d)]	2.1	42.3	2.35	0.582	0.849	-49	35.9	0.0	14.0	28.0	14.9
Intermediate to Lower Shell Circ. Weld Seam AB (Heat # 4P4784)	1.1	68.0	6.99	1.73	1.151	-49	78.3	0.0	28.0	56.0	85.3

Table 4.2.4-2 Calculation of the ART Values at the 3/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at the End of Period of Extended Operation (56 EFPY)[(a)]

Material	RG 1.99, Rev. 2 Position	CF	Surface Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)(g)]	3/4T Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)]	3/4T FF[(b)]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)[(c)]	M (°F)	ART (°F)
Using credible surveillance data[(d)]	2.1	42.3	6.99	1.73	1.151	-49	48.7	0.0	14.0	28.0	27.7
Lower Shell Long. Weld Seams BA & BB (Heat # 4P4784)	1.1	68.0	2.39	0.592	0.853	-49	58.0	0.0	28.0	56.0	65.0
Using credible surveillance data[(d)]	2.1	42.3	2.39	0.592	0.853	-49	36.1	0.0	14.0	28.0	15.1
Extended Beltline Materials											
Nozzle Shell 12-1 (Heat # C9955-2)	1.1	90.1	0.309	0.0767	0.366	9	33.0	0.0	16.5	33.0	74.9
Nozzle Shell 12-2 (Heat # C0123-2)	1.1	82.6	0.309	0.0767	0.366	15	30.2	0.0	15.1	30.2	75.4
Nozzle to Intermediate Shell Circ. Weld Seam AC (Heat # 4P4784)	1.1	68.0	0.328	0.0814	0.377	-49	25.6	0.0	12.8	25.6	2.3
Using credible surveillance data[(d)]	2.1	42.3	0.328	0.0814	0.377	-49	15.9	0.0	8.0	15.9	-17.1
Nozzle Shell Long. Weld Seams BE and BF[(f)]	1.1	82.0	0.309	0.0767	0.366	10	30.0	0.0	15.0	30.0	70.0

Footnote(s):

(a) The RG 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(c) Per the guidance of RG 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed $0.5*\Delta RT_{NDT}$ for either base metals or welds, with or without surveillance data.

(d) The credibility evaluation for the surveillance data determined that the surveillance data for the Intermediate Shell 11-1 (Heat # A9154-1) is deemed non-credible and the Surveillance Weld (Heat # 4P4784) is deemed credible.

(e) The surface fluence values for the RV materials were interpolated from the data in Table 4.2.1-1. The 1/4T and 3/4T fluence values were calculated from the surface fluence, the RV beltline thickness (7.75 inches) and equation $f = f_{surf} * e^{-0.24\,(x)}$ from RG 1.99, Revision 2, where x = the depth into the RV wall (inches).

(f) Exposure values for the nozzle shell longitudinal welds are bounded by the exposure values for the nozzle shell.

(g) All fluence values are based on the projections which include the 10% bias on the core periphery.

Table 4.2.4-3 Calculation of the ART Values for the Reactor Vessel Extended Beltline Nozzle Materials at the End of Period of Extended Operation (56 EFPY)[(a)]

Material	RG 1.99, Rev. 2 Position	CF	Maximum Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(d)]	Max FF[(b)]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)[(c)]	M (°F)	ART (°F)
Inlet Nozzle 436B-1 (Heat # Q2Q41W)	1.1	92.1	0.0239	0.192	-20	17.7	0.0	8.8	17.7	15.4
Inlet Nozzle 436B-2 (Heat # Q2Q39W)	1.1	93.0	0.0239	0.192	0	17.8	0.0	8.9	17.8	35.7
Inlet Nozzle 436B-3 (Heat # Q2Q39W)	1.1	93.0	0.0239	0.192	-20	17.8	0.0	8.9	17.8	15.7
Outlet Nozzle 437B-1 (Heat # Q2Q40)	1.1	93.0	0.0102	0.111	-10	10.3	0.0	5.2	10.3	10.6
Outlet Nozzle 437B-2 (Heat # Q2Q40W)	1.1	93.0	0.0102	0.111	-10	10.3	0.0	5.2	10.3	10.6
Outlet Nozzle 437B-3 (Heat # Q2Q44W)	1.1	92.6	0.0102	0.111	0	10.3	0.0	5.1	10.3	20.5
Inlet/Outlet Nozzle Forgings to Nozzle Shell Weld Seams 15A/B/C & 16A/B/C	1.1	82.0	0.0239	0.192	10	15.7	0.0	7.9	15.7	41.5

Footnote(s):

(a) The RG 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(c) Per the guidance of RG 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed 0.5*ΔRT_{NDT} for either base metals or welds, with or without surveillance data.

(d) All fluence values are based on the projections which include the 10% bias on the core periphery.

Table 4.2.4-4 Calculation of the ART Values at the 1/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at the End of the Subsequent Period of Extended Operation (72 EFPY)[(a)]

Material	RG 1.99, Rev. 2 Position	CF	Surface Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)(g)]	1/4T Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)]	1/4T FF [(b)]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F) [(c)]	M (°F)	ART (°F)
Beltline Materials											
Intermediate Shell 11-1 (Heat # A9154-1)	1.1	65.0	9.04	5.68	1.427	21	92.7	0.0	17.0	34.0	147.7
Using non-credible surveillance data[(d)]	2.1	43.5	9.04	5.68	1.427	21	62.1	0.0	17.0	34.0	117.1
Intermediate Shell 11-2 (Heat # A9153-2)	1.1	58.0	9.04	5.68	1.427	-20	82.7	0.0	17.0	34.0	96.7
Lower Shell 10-1 (Heat # C9923-1)	1.1	51.0	9.06	5.69	1.427	5	72.8	0.0	17.0	34.0	111.8
Lower Shell 10-2 (Heat # C9923-2)	1.1	51.0	9.06	5.69	1.427	4	72.8	0.0	17.0	34.0	110.8
Intermediate Shell Long. Weld Seams BC & BD (Heat # 4P4784)	1.1	68.0	3.03	1.90	1.176	-49	80.0	0.0	28.0	56.0	87.0
Using credible surveillance data[(d)]	2.1	42.3	3.03	1.90	1.176	-49	49.7	0.0	14.0	28.0	28.7
Intermediate to Lower Shell Circ. Weld Seam AB (Heat # 4P4784)	1.1	68.0	9.04	5.68	1.427	-49	97.0	0.0	28.0	56.0	104.0

Table 4.2.4-4 Calculation of the ART Values at the 1/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at the End of the Subsequent Period of Extended Operation (72 EFPY)[(a)]

Material	RG 1.99, Rev. 2 Position	CF	Surface Fluence ($x 10^{19}$ n/cm^2, E > 1.0 MeV)[(e)(g)]	1/4T Fluence ($x 10^{19}$ n/cm^2, E > 1.0 MeV)[(e)]	1/4T FF [(b)]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F) [(c)]	M (°F)	ART (°F)
Using credible surveillance data[(d)]	2.1	42.3	9.04	5.68	1.427	-49	60.3	0.0	14.0	28.0	39.3
Lower Shell Long. Weld Seams BA & BB (Heat # 4P4784)	1.1	68.0	3.08	1.93	1.180	-49	80.3	0.0	28.0	56.0	87.3
Using credible surveillance data[(d)]	2.1	42.3	3.08	1.93	1.180	-49	49.9	0.0	14.0	28.0	28.9
Extended Beltline Materials											
Nozzle Shell 12-1 (Heat # C9955-2)	1.1	90.1	0.400	0.251	0.625	9	56.3	0.0	17.0	34.0	99.3
Nozzle Shell 12-2 (Heat # C0123-2)	1.1	82.6	0.400	0.251	0.625	15	51.6	0.0	17.0	34.0	100.6
Nozzle to Intermediate Shell Circ. Weld Seam AC (Heat # 4P4784)	1.1	68.0	0.425	0.267	0.640	-49	43.6	0.0	21.8	43.6	38.1
Using credible surveillance data[(d)]	2.1	42.3	0.425	0.267	0.640	-49	27.1	0.0	13.5	27.1	5.2
Nozzle Shell Long. Weld Seams BE and BF[(f)]	1.1	82.0	0.400	0.251	0.625	10	51.3	0.0	25.6	51.3	112.5

Footnote(s):

(a) The RG 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(c) Per the guidance of RG 1.99, Revision 2, the base metal σ_{Δ} = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_{Δ} = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_{Δ} = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_{Δ} = 14°F for Position 2.1 with credible surveillance data. However, σ_{Δ} need not exceed 0.5*ΔRT_{NDT} for either base metals or welds, with or without surveillance data.

(d) The credibility evaluation for the surveillance data determined that the surveillance data for the Intermediate Shell 11-1 (Heat # A9154-1) is deemed non-credible and the Surveillance Weld (Heat # 4P4784) is deemed credible.

(e) The surface fluence values for the RV materials were interpolated from the data in Table 4.2.1-1. The 1/4T and 3/4T fluence values were calculated from the surface fluence, the RV beltline thickness (7.75 inches) and equation $f = f_{surf} * e^{-0.24\,(x)}$ from RG 1.99, Revision 2, where x = the depth into the RV wall (inches).

(f) Exposure values for the nozzle shell longitudinal welds are bounded by the exposure values for the nozzle shell.

(g) All fluence values are based on the projections which include the 10% bias on the core periphery.

Table 4.2.4-5 Calculation of the ART Values at the 3/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at the End of the Subsequent Period of Extended Operation (72 EFPY)[(a)]

Material	RG 1.99, Rev. 2 Position	CF	Surface Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)(g)]	3/4T Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)]	3/4T FF[(b)]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)[(c)]	M (°F)	ART (°F)
Beltline Materials											
Intermediate Shell 11-1 (Heat # A9154-1)	1.1	65.0	9.04	2.24	1.218	21	79.2	0.0	17.0	34.0	134.2
Using non-credible surveillance data[(d)]	2.1	43.5	9.04	2.24	1.218	21	53.0	0.0	17.0	34.0	108.0
Intermediate Shell 11-2 (Heat # A9153-2)	1.1	58.0	9.04	2.24	1.218	-20	70.7	0.0	17.0	34.0	84.7
Lower Shell 10-1 (Heat # C9923-1)	1.1	51.0	9.06	2.25	1.219	5	62.2	0.0	17.0	34.0	101.2
Lower Shell 10-2 (Heat # C9923-2)	1.1	51.0	9.06	2.25	1.219	4	62.2	0.0	17.0	34.0	100.2
Intermediate Shell Long. Weld Seams BC & BD (Heat # 4P4784)	1.1	68.0	3.03	0.751	0.920	-49	62.5	0.0	28.0	56.0	69.5
Using credible surveillance data[(d)]	2.1	42.3	3.03	0.751	0.920	-49	38.9	0.0	14.0	28.0	17.9
Intermediate to Lower Shell Circ. Weld Seam AB (Heat # 4P4784)	1.1	68.0	9.04	2.24	1.218	-49	82.9	0.0	28.0	56.0	89.9
Using credible surveillance data[(d)]	2.1	42.3	9.04	2.24	1.218	-49	51.5	0.0	14.0	28.0	30.5

Table 4.2.4-5 Calculation of the ART Values at the 3/4T Location for the Reactor Vessel Beltline and Extended Beltline Materials at the End of the Subsequent Period of Extended Operation (72 EFPY)[(a)]

Material	RG 1.99, Rev. 2 Position	CF	Surface Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)(g)]	3/4T Fluence (x 10^{19} n/cm^2, E > 1.0 MeV)[(e)]	3/4T FF[(b)]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)[(c)]	M (°F)	ART (°F)
Lower Shell Long. Weld Seams BA & BB (Heat # 4P4784)	1.1	68.0	3.08	0.763	0.924	-49	62.8	0.0	28.0	56.0	69.8
Using credible surveillance data[(d)]	2.1	42.3	3.08	0.763	0.924	-49	39.1	0.0	14.0	28.0	18.1
Extended Beltline Materials											
Nozzle Shell 12-1 (Heat # C9955-2)	1.1	90.1	0.400	0.0991	0.415	9	37.4	0.0	17.0	34.0	80.4
Nozzle Shell 12-2 (Heat # C0123-2)	1.1	82.6	0.400	0.0991	0.415	15	34.3	0.0	17.0	34.0	83.3
Nozzle to Intermediate Shell Circ. Weld Seam AC (Heat # 4P4784)	1.1	68.0	0.425	0.105	0.427	-49	29.1	0.0	14.5	29.1	9.1
Using credible surveillance data[(d)]	2.1	42.3	0.425	0.105	0.427	-49	18.1	0.0	9.0	18.1	-12.8
Nozzle Shell Long. Weld Seams BE and BF[(f)]	1.1	82.0	0.400	0.0991	0.415	10	34.0	0.0	17.0	34.0	78.1

Footnote(s):

(a) The RG 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(c) Per the guidance of RG 1.99, Revision 2, the base metal σ_Δ= 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_{Δ} = 14°F for Position 2.1 with credible surveillance data. However, σ_{Δ} need not exceed 0.5*ΔRT_{NDT} for either base metals or welds, with or without surveillance data.

(d) The credibility evaluation for the surveillance data determined that the surveillance data for the Intermediate Shell 11-1 (Heat # A9154-1) is deemed non-credible and the Surveillance Weld (Heat # 4P4784) is deemed credible.

(e) The surface fluence values for the RV materials were interpolated from the data in Table 4.2.1-1. The 1/4T and 3/4T fluence values were calculated from the surface fluence, the RV beltline thickness (7.75 inches) and equation $f = f_{surf} * e^{-0.24 (x)}$ from RG 1.99, Revision 2, where x = the depth into the RV wall (inches).

(f) Exposure values for the nozzle shell longitudinal welds are bounded by the exposure values for the nozzle shell.

(g) All fluence values are based on the projections which include the 10% bias on the core periphery.

Table 4.2.4-6 Calculation of the ART Values for the Reactor Vessel Extended Beltline Nozzle Materials at the End of the Subsequent Period of Extended Operation (72 EFPY)[(a)]

Material	RG 1.99, Rev. 2 Position	CF	Maximum Fluence (x 10^{19} n/cm^2, E > 1.0 MeV) (e)(d)	Max FF[(b)]	$RT_{NDT(U)}$ (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)[(c)]	M (°F)	ART (°F)
Inlet Nozzle 436B-1 (Heat # Q2Q41W)	1.1	92.1	0.0310	0.224	-20	20.6	0.0	10.3	20.6	21.2
Inlet Nozzle 436B-2 (Heat # Q2Q39W)	1.1	93.0	0.0310	0.224	0	20.8	0.0	10.4	20.8	41.6
Inlet Nozzle 436B-3 (Heat # Q2Q39W)	1.1	93.0	0.0310	0.224	-20	20.8	0.0	10.4	20.8	21.6
Outlet Nozzle 437B-1 (Heat # Q2Q40)	1.1	93.0	0.0132	0.132	-10	12.3	0.0	6.1	12.3	14.5
Outlet Nozzle 437B-2 (Heat # Q2Q40W)	1.1	93.0	0.0132	0.132	-10	12.3	0.0	6.1	12.3	14.5
Outlet Nozzle 437B-3 (Heat # Q2Q44W)	1.1	92.6	0.0132	0.132	0	12.2	0.0	6.1	12.2	24.4
Inlet/Outlet Nozzle Forgings to Nozzle Shell Weld Seams 15A/B/C & 16A/B/C	1.1	82.0	0.0310	0.224	10	18.4	0.0	9.2	18.4	46.7

Footnote(s):

(a) The RG 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(c) Per the guidance of RG 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the base metal σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per RG 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and the weld metal σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed 0.5*ΔRT_{NDT} for either base metals or welds, with or without surveillance data.

(d) All fluence values are based on the projections which include the 10% bias on the core periphery.

4.2.5 PRESSURE-TEMPERATURE LIMITS

TLAA Description:

10 CFR 50, Appendix G, requires that the reactor vessel (RV) be maintained within established P-T limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor vessel (RV) is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RV fluence.

The current P-T limits are based upon fluence projections for 60 years of plant operation. Therefore, the P-T limits analyses meet the definition of 10 CFR 54.3(a) and have been identified as TLAAs.

TLAA Evaluation:

Heatup and cooldown limit curves are calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline region of the RV. The most limiting RT_{NDT} of the material in the core region (beltline) of the RV is determined by using the unirradiated RV material fracture toughness properties and estimating the irradiation induced shift (ΔRT_{NDT}).

RT_{NDT} increases as the material is exposed to fast neutron irradiation; therefore, to find the most limiting core region (beltline) RT_{NDT} at any time, ΔRT_{NDT} due to the neutron radiation exposure associated with that time must be added to the original unirradiated RT_{NDT}. Using the ART values, P-T limit curves are determined in accordance with the requirements of 10 CFR 50, Appendix G, as augmented by ASME Code, Section XI, Appendix G.

The current Technical Specification P-T limits for 56 EFPY are based on the latest capsule data.

According to NUREG-2192, Section 4.2.2.1.4, the P-T limits for the subsequent period of extended operation need not be submitted as part of the subsequent license renewal application since the P-T limits are required to be updated through the 10 CFR 50.90 licensing process when necessary for P-T limits that are located in the Technical Specifications. The current licensing basis will ensure that the P-T limits for the subsequent period of extended operation will be updated prior to exceeding the EFPY for which they remain valid.

This section determines the applicability term of the end of period of extended operation P-T limit curves by comparing the ART values contained in the analysis of record (AOR) with the ART values calculated using the updated fluence projections and materials information. If the ART values used in the previous analysis are higher or equal to the ART values calculated using the updated fluence and material properties, then the applicability term of the current curves will remain unchanged. If the ART values used in the previous analysis are lower than the ART values calculated using the updated fluence and material properties, then the applicability term of the current curves may need to be shortened. This new period of applicability can be calculated based on a comparison of the ART values and linear interpolation using the fluence projections.

Table 4.2.4-1, Table 4.2.4-2, Table 4.2.4-3, Table 4.2.4-4, Table 4.2.4-5 and Table 4.2.4-6 calculate the beltline and extended beltline ART values at the end of period of extended operation (56 EFPY) and the end of the subsequent period of extended operation (72 EFPY). The limiting end of the subsequent period of extended operation ART values corresponds to the Intermediate Shell 11-1.

Table 4.2.5-1 below (extracted from WCAP-18728-NP) compares the TLAA limiting ART values at the end of the period of extended operation and the end of the subsequent period of extended operation to the limiting ART values used in development of the current Technical Specifications P-T limit curves as described in WCAP-16305-NP, Revision 0, “V. C. Summer Heatup and Cooldown Curves for Normal Operation” (Reference 4.8-10).

Table 4.2.5-1 Summary of the Limiting ART Values

Vessel Wall Location	Limiting ART[a] (°F)		
	P-T Limit Curves AOR	56 EFPY	72 EFPY
1/4T	153	144.4	147.7
3/4T	138	129.8	134.2

Footnote(s):

(a) The limiting material (Intermediate Shell 11-1) corresponds to an axial flaw which is more limiting than a circumferential flaw.

Table 4.2.5-1 shows that the end of the subsequent period of extended operation ART values at the 1/4T and 3/4T locations remain bounded by the ART values used in the current P-T limit curves. Thus, the P-T limit curves implemented in the Technical Specifications will remain valid through the end of the subsequent period of extended operation (72 EFPY) for the cylindrical shell materials. The extension of the P-T limit curve is allowed because the redefinition of the Intermediate Shell 11-1 (Heat # A9154-1) initial RT_{NDT} in PWROG-21037-NP (Reference 4.8-25) resulted in a 9°F reduction.

Note that the terms of applicability for the P-T limits also implicitly confirm the bolt up temperature and flange temperature limits. The bolt up temperature and flange-notch temperature limit are not affected by embrittlement; thus, they are unaffected by license renewal and may remain the same. Since development of the P-T limit curves for license renewal in WCAP-16305-NP, the closure head has been replaced. However, the RT_{NDT} of the replacement RV closure head is lower than the original head flange; thus, the P-T limit curves are not negatively affected.

Inlet and Outlet Nozzles P-T Limit Curves

NRC Regulatory Issue Summary (RIS) 2014-11, “Information On Licensing Applications For Fracture Toughness Requirements For Ferritic Reactor Coolant Pressure Boundary Components,” requires that the P-T limit curves account for the higher stresses in the nozzle corner region due to the potential for more restrictive P-T limits, even if the RT_{NDT} for these components are not as high as those of the RV beltline shell materials that have simpler geometries. As shown in Table 4.2.1-1, the 80-year fluence at the inlet/outlet nozzle postulated 1/4T flaw is below the fluence threshold of RIS 2014-11, 1 x 10^{17} n/cm^2 (E > 1.0 MeV). Since the fluence at inlet/outlet nozzle postulated 1/4T flaw locations is less than 1 x 10^{17} n/cm^2 (E > 1.0 MeV) the inlet/outlet nozzles are screened out of the extended beltline region. Therefore, the inlet/outlet nozzles are confirmed not to be limiting.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

Since the P-T limits will be updated through the 10 CFR 50.90 process at a later, appropriate date, the effects of aging on the intended function(s) of the RV will be adequately managed for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

4.2.6 LOW TEMPERATURE OVERPRESSURE PROTECTION

NOTE: Cold Overpressure Protection System (COPS) is the site-specific term used for the Low Temperature Overpressure Protection (LTOP) system.

TLAA Description:

The LTOP system is required by Technical Specification Limiting Condition for Operation 3.4.9.3. Two residual heat removal (RHR) suction relief valves provide automatic relief capability during design basis mass injection and design basis heat injection transients to prevent the reactor coolant system pressure from exceeding the P-T limit curves based on 10 CFR 50, Appendix G.

The LTOPS setpoints are based on the P-T limits calculation which is a TLAA. Additionally, the relief valves characteristics, such as the lift setpoints, must be adequate to remain within the P-T limit curves. Therefore, the LTOP analysis, which demonstrates the capability of the relief valves to protect the Appendix G, Pressure-Temperature (P-T) limits, meets the definition of 10 CFR 54.3(a) and has been identified as a TLAA.

TLAA Evaluation:

Per FSAR Section 5.5.7.3.4 the auto-closure interlock has been removed from the RHR suction isolation valves, thereby preventing isolation of the RHR system from the reactor coolant system during high pressure conditions. As a result, the RHR relief valves are a suitable option to provide LTOP. The RHR suction relief valves will protect both the reactor vessel (RV) Appendix G P-T limits and 110% of the RHR design pressure as long as the valve capacity is not exceeded during the design basis mass injection and heat injection transients. The RHR suction relief valve capacity is

900 gpm at 450 psig, 400°F with 50 psig backpressure, the maximum developed backpressure during a LTOP transient could be as high as 136.5 psig which results in a minimum RHR suction relief valve capacity of 796 gpm. For the mass injection transient, the worst case flow rate is determined to be 628.2 gpm which is less than 796 gpm. Thus, the RHR relief valve capacity is acceptable for the mass injection transient.

The LTOPS enabling temperature was calculated using the methods of ASME Code Case N-641 to be 200°F (without uncertainty). In accordance with the methodology in WCAP-14040-A, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,” (Reference 4.8-19) uncertainties are applied in the LTOP analysis. Since LTOP uses the mechanical RHR relief valves, a pressure uncertainty does not apply. The wide range temperature uncertainty is 26°F. With the temperature uncertainty of 26°F applied, the minimum arming/enabling temperature is 226°F. Technical Specification 3.4.9.3 currently specifies an LTOP enabling temperature of 300°F, which remains conservative and can be maintained.

The RV Appendix G P-T limits and the RHR system design pressure limit are protected by a single RHR suction relief valve for a design basis mass injection transient from a single centrifugal charging pump over the full temperature range where the RHR system can be aligned (i.e., RCS temperature ≤ 350°F), which bounds the full temperature range applicable to LTOP (i.e., 60 ≤ RCS temperature ≤ 300°F).

The RV Appendix G P-T limits are protected by a single RHR suction relief valve for a design basis heat injection transient from the startup of one reactor coolant pump with the steam generator secondary side a maximum of 50°F hotter than the lowest cold leg temperature over the full temperature range applicable to LTOP (i.e., 60 ≤ RCS temperature ≤ 300°F).

For the heat injection transient, a single RHR suction relief valve is capable of protecting the RHR system design pressure limit for actual RCS temperatures ≤ 220°F. At RCS temperatures > 220°F, both RHR suction relief valves need to be credited to protect 110% of the RHR system design pressure. This is acceptable since the relief valves are passive components and once an RHR train is aligned, it cannot be spuriously isolated.

The LTOPS enabling temperature and relief valve analyses that demonstrate the capability of the relief valves to protect the P-T limit curves are TLAAs that require reevaluation whenever the P-T curves are revised. Section 4.2.5 demonstrates that the current P-T limit curves continue to remain valid for the subsequent period of extended operation (72 EFPY). Therefore, the LTOP enabling temperature and analyses also remain valid for the subsequent period of extended operation, as demonstrated by the evaluation summarized above.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The LTOP system capabilities and enabling temperature will remain valid for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

4.3 METAL FATIGUE

Fatigue analyses are required on components designed to ASME Code, Section III. Searches were performed to identify any other potential fatigue TLAAs within the CLB. Each potential fatigue TLAA was evaluated against the definition in 10 CFR 54.3(a) to determine whether the six criteria were met for the subsequent period of extended operation. Those that were identified as fatigue TLAAs are described and evaluated in the following subsections:

- Transient Cycle Projections for 80 years (Section 4.3.1)
- ASME Code, Section III, Class 1 Fatigue Analyses (Section 4.3.2)
- Non-Class 1 Allowable Stress Analyses (Section 4.3.3)
- Environmentally-Assisted Fatigue (Section 4.3.4)
- High-Energy Line Break Analysis (Section 4.3.5)

Major plant changes include steam generator replacement (1994); 4.5% power uprate (approved in 1996); replacement of an alloy 600 weld on the Loop 'A' reactor coolant hot leg piping (2002); stress improvement of the alloy 600 buttering and welds on the Loop 'B' and 'C' reactor coolant hot leg piping (2002); preemptive full structural weld overlays on pressurizer surge, safety, relief and spray nozzles (2008); upflow conversion (2009); and replacement of the RV closure head and CRDMs (2017). Potential impacts on fatigue usage are discussed further in the following sections, as applicable.

4.3.1 TRANSIENT CYCLE PROJECTIONS FOR 80 YEARS

Fatigue analyses are based upon numbers and amplitudes of thermal and pressure transients. FSAR, Table 5.2-2 (Reference 1.7-18) lists the design transients and associated design cycles. The intent of the design-basis transient definitions is to bound a wide range of events with varying ranges of severity in temperature and pressure. CLB fatigue analyses are based upon the original number of design cycles (40 years) and were postulated to bound 60 years of service life in fatigue evaluations performed in support of initial license renewal. Since the fatigue analyses are based on the 40-year design cycles, these fatigue analyses are considered TLAAs that require evaluation for the subsequent period of extended operation.

A review of the Fatigue Monitoring program (B3.1) data was performed to identify the number of cumulative cycles for each transient type that occurred through December 31, 2019. Baseline cycle counts were projected through an 80-year operating life, based on the actual accumulation history over the life of the plant. They do not represent a revision of the design basis. These transient cycle projections are shown in Table 4.3.1-1 “80-Year Transient-Cycle Projections”. A linear-rate cycle extrapolation of the total past operating period was used to project the number of future occurrences beginning December 31, 2019 and ending August 6, 2062, at the end of 80 years of plant operation.

As shown in Table 4.3.1-1, the numbers of projected cycles for 80 years of plant operation are less than the numbers of 40-year design cycles. That is, the 40-year design cycles bound the 80-year projected cycles. In order to ensure these design cycles used in the Class 1 component fatigue analyses remain bounding of actual plant cycles, the Fatigue Monitoring program (B3.1) will track cycles for fatigue transients listed in FSAR Table 5.2-2, reproduced in Table 4.3.1-1, and ensure corrective action is taken prior to exceeding fatigue design limits. The 80-year projections are for use in evaluating the fatigue TLAAs described in the remaining Section 4.3 subsections.

The effects of fatigue on the intended function(s) of Safety Class 1 components will be adequately managed by the Fatigue Monitoring program (B3.1) during the subsequent of extended operation.

Table 4.3.1-1 80-Year Transient-Cycle Projections

Transients	Cumulative Transient Cycles (12/31/2019)	80-Year Transient-Cycle Projections	CLB Cycle Limit (40-Year Design Cycles)[a]
Normal Conditions			
Heatup at 100°F/hr	68	148	200
Cooldown at 100°F/hr	67	148	200
Unit Loading at 5% of Full Power/Min	306	662	13200
Unit Unloading at 5% of Full Power/Min	226	489	13200
Step Load Increase of 10% of Full Power	48	104	2000
Step Load Decrease of 10% of Full Power	30	65	2000
Large Step Load Decrease with Steam Dump	58	126	200
Steady State Fluctuations – Initial[c]	34,000	73,514	1.5×10^5
Steady State Fluctuations – Random[c]	670,000	1,448,649	3.0×10^6
Feedwater Heater Out of Service	0	2	40
Upset Conditions			
Loss of Load	17	37	80
Loss of Power	7	16	40
Partial Loss of Flow	2	5	80
Reactor Trip from Full Power without Cooldown (Case A)[e]	54	117	230
Reactor Trip from Full Power with Cooldown, No Safety Injection (Case B)[e]	31	68	160
Reactor Trip from Full Power with Cooldown and Safety Injection (Case C)[e]	4	9	10
Inadvertent Auxiliary Spray	4	9	10

Table 4.3.1-1 80-Year Transient-Cycle Projections

Transients	Cumulative Transient Cycles (12/31/2019)	80-Year Transient-Cycle Projections	CLB Cycle Limit (40-Year Design Cycles)[a]
Operational Basis Earthquake	0	40[f]	400
Excessive Feedwater Flow	6	13	30
Faulted Conditions[b]			
Reactor Coolant Branch Line Pipe Break	0	1	1
Large Steam Line Break	0	1	1
Steam Generator Tube Rupture	0	(g)	(g)
Safe Shutdown Earthquake	0	1	1
Test Conditions[d]			
Turbine Roll Test	6	6	10
Primary Side Hydrostatic Test	2	2	5
Secondary Side Hydrostatic Test	3	3	5
Primary Side Leakage Test	14	14	50

Footnote(s):

(a) From FSAR Table 5.2-2.

(b) In accordance with the ASME Boiler and Pressure Vessel Code, Section III, faulted conditions are not included in fatigue evaluation. Faulted condition transients will be evaluated under the Corrective Action Program if one ever occurs.

(c) Steady-state fluctuation transients are not fatigue-significant, so need not be counted or tracked.

(d) There are no projected cycles since there are no plans to perform any of these tests in the future.

(e) Reactor Trip from Full Power, shown as 400 cycles in FSAR Table 5.2-2, is the combination of Cases A, B, and C.

(f) This cycle projection is represented as 2 events with 20 cycles per event, which is consistent with FSAR Table 5.2-2.

(g) Per FSAR Table 5.2-2, included in Reactor Trip from Full Power.

4.3.2 ASME CODE, SECTION III, CLASS 1 FATIGUE ANALYSES

Fatigue analyses were performed in accordance with the ASME Code, Section III requirements. Each analysis was required to demonstrate that the cumulative usage factor (CUF) for the component will not exceed the ASME Code, Section III, design limit of 1.0 when the component is exposed to the 40-year design transients. Where warranted, fatigue waivers were performed in accordance with ASME Section III requirements in lieu of a fatigue analysis.

The following Safety Class 1 components have fatigue analyses or fatigue waivers that have been identified as TLAAs that have been evaluated for the subsequent period of extended operation:

- Control Rod Drive Mechanism (Section 4.3.2.1)
- Pressurizer (Section 4.3.2.2)
- Reactor Coolant Pumps (Section 4.3.2.3)
- Reactor Vessel and Replacement Reactor Vessel Closure Head (Section 4.3.2.4)
- Steam Generators (Section 4.3.2.5)
- ASME Code, Section III, Class 1 Component Fatigue Waivers (Section 4.3.2.6)
- ASME Code, Section III, Class 1 Piping Fatigue Analyses (Section 4.3.2.7)
- Pressurizer Surge Line (Section 4.3.2.8)

4.3.2.1 Control Rod Drive Mechanism

TLAA Description:

The original control-rod drive mechanisms (CRDMs) were replaced during the installation of the replacement RV closure head. The fatigue evaluations of the pressure retaining portions of the replacement CRDMs were performed in accordance with the requirements of the ASME Code, Section III. Since these fatigue analyses consider transient cycles that occur over the life of the plant, they have been identified as TLAAs. The CUF values for the CRDM components are less than 1.0.

TLAA Evaluation:

As shown in Table 4.3.1-1, “80-Year Transient-Cycle Projections,” the 40-year design cycles are postulated to bound 80 years of plant operation. Therefore, the fatigue analyses for the CRDM components remain valid for the subsequent period of extended operation. In order to ensure the design cycles used in the CRDM component fatigue analyses remain bounding, the Fatigue Monitoring program (B3.1) will track the design transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding the 40-year fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of CRDM components will be adequately managed by the Fatigue Monitoring program (B3.1) for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.2.2 Pressurizer

TLAA Description:

The pressurizer (PZR) is a vertical, cylindrical, pressure vessel with a 1,400 ft^3 internal volume. The fatigue evaluations of the PZR were performed in accordance with the requirements of the ASME Code, Section III. Since these fatigue evaluations analyzed the transient cycles that occur over the life of the plant, they have been identified as TLAAs. The CUF values for the PZR locations are less than 1.0.

TLAA Evaluation:

As shown in Table 4.3.1-1, “80-Year Transient-Cycle Projections,” the 40-year design cycles are postulated to bound 80 years of plant operations. Therefore, the fatigue analyses for the PZR components remain valid through the subsequent period of extended operation. In order to ensure the design cycles used in the PZR component fatigue analyses remain bounding, the Fatigue Monitoring program (B3.1) will track the design transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding the 40-year fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the PZR components will be adequately managed by the Fatigue Monitoring program (B3.1) for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.2.3 Reactor Coolant Pumps

TLAA Description:

The reactor coolant pumps (RCPs) are Westinghouse, Model 93A. Fatigue evaluations of the RCPs were performed in accordance with the requirements of the ASME Code, Section III. Since these fatigue evaluations analyzed transient cycles that occur over the life of the plant, they have been identified as TLAAs. The CUF values for the RCP components are less than 1.0.

TLAA Evaluation:

As shown in Table 4.3.1-1, “80-Year Transient-Cycle Projections,” the 40-year design cycles are postulated to bound 80 years of plant operations. Therefore, the fatigue analysis for the reactor coolant pump components remains valid through the subsequent period of extended operation. In order to ensure the design cycles used in the reactor coolant pump fatigue analyses remain bounding, the Fatigue Monitoring program (B3.1) will track the design transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding the 40-year fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the RCP components will be adequately managed by the Fatigue Monitoring program (B3.1) for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.2.4 Reactor Vessel and Replacement Reactor Vessel Closure Head

TLAA Description:

The Westinghouse-designed reactor vessel (RV) has three loops. The replacement RV closure head and associated Control Rod Drive Mechanisms (CRDMs) were installed in 2017, along with an Integrated Head Assembly (IHA). The fatigue analyses for these ASME Section III, Class 1 components are based upon the 40-year design transient cycles. The fatigue analyses for the RV, replacement RV closure head, and CRDMs have therefore been identified as TLAAs for the subsequent period of extended operation. The CUF values for these components are less than 1.0.

TLAA Evaluation:

As shown in Table 4.3.1-1, “80-Year Transient-Cycle Projections,” the 40-year design cycles for the ASME Code, Section III, Class 1 components and piping are postulated to bound 80 years of plant operation. Therefore, the fatigue analyses for the RV and replacement RV closure head will remain valid through the subsequent period of extended operation.

Evaluation of the fatigue analysis for the replacement CRDM is provided in Section 4.3.2.1.

In order to ensure the design cycles used in the RV component fatigue analyses remain bounding, the Fatigue Monitoring program (B3.1) will track the design transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding the 40-year fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) for the RV and replacement RV closure head will be adequately managed by the Fatigue Monitoring program (B3.1) for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.2.5 Steam Generators

TLAA Description:

The original ASME Section III, Class 1 steam generators were replaced in 1994, which was approximately 12 years after initial plant startup. The design analyses for the ASME Section III, Class 1 replacement steam generators (SGs) are based upon 40-year transient design cycles and have therefore been identified as TLAAs for the subsequent period of extended operation

TLAA Evaluation:

As shown in Table 4.3.1-1, “80-Year Transient-Cycle Projections,” the 40-year design cycles are postulated to bound 80 years of plant operations. Since the steam generators were replaced in 1994, the service life of the replacement SGs through the subsequent period of extended operation will be less than 69 years, so the replacement SGs will experience a lower number of cycles than the 80-year projections. Therefore, the fatigue analyses for the SG components will remain valid through the subsequent period of extended operation.

In order to ensure the design cycles used in the SG component fatigue analyses remain bounding, the Fatigue Monitoring program (B3.1) will track the design transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding the 40-year fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the SG components will be adequately managed by the Fatigue Monitoring program (B3.1) for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.2.6 ASME Code, Section III, Class 1 Component Fatigue Waivers

TLAA Description:

Fatigue analyses for ASME Section III, Class 1, components are performed in accordance with the ASME Code, Section III, paragraph NB-3222.4(e). Each analysis is required to demonstrate that the CUF for the component will not exceed the Code design limit of 1.0. A detailed fatigue analysis is not required if the cyclic loading applicable to these components conforms to the fatigue-exemption criteria specified in ASME Code, Section III, paragraph NB-3222.4(d). These exemptions are commonly called fatigue waivers.

The equipment listed in Table 4.3.2.6-1, "Class 1 Equipment Fatigue Waivers," includes sub-components that were designed in accordance with the fatigue waiver criteria specified in ASME Code, Section III, paragraph NB-3222.4(d). These fatigue waivers demonstrated that the requirements of NB-3222.4(d) were met, so no fatigue analyses were required. Since they are based upon numbers of cycles predicted for the life of the plant, these fatigue waivers have been identified as TLAAs for the subsequent period of extended operation.

Table 4.3.2.6-1 Class 1 Equipment Fatigue Waivers

Equipment	Component
SG	Plug [(a)]
RCP	Support Feet [(a)]
	Weir Plate [(a)]
	Seal Housing, Ring Clamp and Bolts [(b)]
	Suction and Discharge Nozzles [(a)]

Footnote(s):

(a) The fatigue waiver for this component this component satisfies the conditions of ASME Code, Section III NB-3222.4(d).

(b) The fatigue waiver for this component this component satisfies the conditions of ASME Code, Section III N-415.1. This is the 1969 equivalent of ASME Code, Section III NB-3222.4(d).

TLAA Evaluation:

In order to demonstrate that the fatigue waiver evaluations remain valid through the subsequent period of extended operation, the 80-year transient cycle projections were compared to the 40-year design transients as shown in Table 4.3.1-1. The 40-year design transients analyzed in these fatigue waivers bound the 80-year projected transient cycles applicable to these fatigue waivers, so the fatigue waivers remain valid. The Fatigue Monitoring program (B3.1) will monitor the transient cycles that are the inputs to the fatigue waiver analyses and require corrective action prior to potentially exceeding the fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The ASME Code, Section III, Class 1 component fatigue waivers will be adequately managed by the Fatigue Monitoring program (B3.1) for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.2.7 ASME Code, Section III, Class 1 Piping Fatigue Analyses

TLAA Description:

The design reports for: 1) the reactor coolant loop (RCL) pressure boundary piping; 2) the branch nozzles attached to the main RCL piping; and 3) the auxiliary-line piping, connected to the reactor coolant branch nozzles, include detailed stress and fatigue evaluations prepared in accordance with the requirements of the ASME Code, Section III, Subsection NB.

Since the original design analyses were prepared, the following enhancements have been implemented:

- Replacement of the Alloy 600 weld on RCL ’A’ reactor vessel shell-to-outlet nozzle in 2000.
- Mechanical stress improvement of Alloy 600 buttering and welds on RCL ’B’ and RCL ’C’ piping in 2002.
- Installation of full structural weld overlays of dissimilar metal joints associated with the pressurizer surge line, pressurizer spray line, pressurizer safety-relief nozzles, and pressurizer spray nozzle in 2008.

Each enhancement was analyzed in accordance with the requirements of the ASME Code, Section III and the applicable design specification. Fatigue analyses for the piping components are based upon the 40-year design transients.

The CUF values for the above piping components are less than 1.0. Since these fatigue evaluations are based upon the 40-year design transients, they have been identified as TLAAs requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

The Class 1 RCL and auxiliary piping components that are subject to fatigue evaluation are summarized as follows:

- Reactor Coolant Loops 1, 2, and 3 Hot Leg Piping
- Reactor Coolant Loops 1, 2, and 3 Cold Leg Piping
- Reactor Coolant Loops 1, 2, and 3 Crossover Piping
- Safety Injection (SI) Accumulator Piping
- Cold Leg SI Piping
- Hot Leg SI Piping
- Residual Heat Removal (RHR) Piping

- Normal and Alternate Charging Piping
- Normal Letdown with Drain Piping
- Drain Piping
- Excess Letdown with Drain Piping
- Pressurizer (PZR) Surge Line Piping
- PZR Spray Line Piping
- PZR Safety and Relief Piping

The 40-year design transient cycles evaluated in the ASME Code, Section III fatigue analyses for the piping components identified above have been demonstrated to bound the corresponding 80-year projected transient cycles for the transients shown in Table 4.3.1-1. Therefore, the CUF values will remain less than 1.0 for the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The CUF values for these ASME Code, Section III, Class 1 piping components will remain less than 1.0. Therefore, the fatigue analyses remain valid for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

4.3.2.8 Pressurizer Surge Line

TLAA Description:

NRC Inspection and Enforcement Bulletin (IEB) 88-11, issued in December 1988, requested utilities to establish and implement a program to confirm the integrity of the pressurizer surge line. The program required both visual inspection of the surge line and demonstration that the design requirements of the surge line are satisfied, including the consideration of thermal stratification effects. The demonstration was an ASME Code, Section III, NB-3200 fatigue analysis to account for thermal stratification. The analysis uses time-limited assumptions, including thermal and pressure transients and operating cycles for the licensed life of the plant and has been identified as a TLAA requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

The analyses performed to demonstrate compliance with design requirements and IEB 88-11 considered ASME Code, Section III, Class 1 requirements and thermal stratification, using 40-year design transients identified in Table 4.3.1-1. Pressurizer surge line stratification sub-transients were developed based on plant operating procedures, surge line monitoring data from similar units, and historical plant records. The thermal stratification cycles used in the analyses are based upon the numbers of heatup and cooldown events. Since the 40-year design transients used in these analyses, including thermal stratification, have been demonstrated to bound the 80-year cycle projections, as shown in Table 4.3.1-1, the CUF values will remain less than 1.0 through the subsequent period of extended operation. In addition, a flaw tolerance evaluation has been performed for the pressurizer surge line to manage environmentally- assisted fatigue (EAF) as shown in Section 4.3.4. The Fatigue Monitoring program (B3.1) tracks the transient cycles used in these flaw-tolerance evaluations.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The CUF values for the pressurizer surge line will remain less than 1.0 and therefore, remain valid for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

4.3.3 NON-CLASS 1 ALLOWABLE STRESS ANALYSES

TLAA Description:

Nuclear piping and components, designated Safety Class 2a, 2b, or 3 on station drawings, are constructed in accordance with the ASME Code, Section III, “Nuclear Power Plant Components,” 1974 Edition and Addenda, Subsections NC and ND.

Non-Class 1 (Balance of Plant) piping is constructed to “The Power Piping Code,” ANSI B31.1, 1967 Edition with addenda through 1972.

For Non-Class 1 piping systems constructed in accordance with the above-cited codes, explicit analyses of cumulative fatigue usage are not required. Instead, cyclic loading is considered in a simplified manner in the design process. Allowable thermal stresses are reduced using a stress-range reduction factor based on the number of anticipated thermal cycles expected during the component operating lifetime. Stress-range reduction factors are specified in ASME Code, Section III (1974 Edition and Addenda), Table NC/ND-3611.2(e)-1 and ANSI B31.1 (1967 Edition through 1972 Addenda), Table 102.3.2(c). No reduction of allowable stresses is required for piping that is subjected to less than 7,000 equivalent full-temperature cycles during plant service. The stress-range reduction factor for higher numbers of fatigue cycles is less than 1.0 and is gradually reduced until a range of 100,000 cycles is reached. For piping anticipated to experience 100,000 or more equivalent full-temperature cycles, the allowable stress range would be reduced to half of the maximum nominal allowable stress. The evaluations for required stress-reduction factors are implicit fatigue analyses because they are based on the number of fatigue cycles anticipated for the life of the component. Therefore, they are TLAAs requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

Non-Class 1 ASME Code, Section III and ANSI B31.1 piping systems are generally subject to continuous steady-state operation, and operating temperatures vary only during plant heatup and cooldown, during plant transients, or during periodic testing. Portions of Non-Class 1 piping systems that are attached to the reactor coolant system or other power cycle related systems are subject to a similar number or fewer cycles as the reactor coolant system. These include extraction steam, feedwater, gland sealing steam, main steam dump, main steam, reactor coolant, residual heat, and safety injection systems. Portions of some of these systems are normally isolated from the normal power cycle and would experience fewer cycles than those portions at the system boundary. The expected number of transients for these systems is much less than 7,000 cycles. Therefore, the stress-range reduction factors applied to the piping remain applicable and the implicit TLAAs remain valid for the subsequent period of extended operation.

Portions of the following Non-Class 1 systems are affected by thermal and pressure transients that are different than the reactor coolant and power cycles discussed above: auxiliary boiler steam and feedwater, steam generator blowdown, boron recycle, chemical and volume control, chemical volume and control vents and drains, diesel generator services, emergency feedwater, nuclear sampling, liquid waste processing, and turbine cycle sampling systems.

The basis for cycle projections have been reviewed for these systems to validate that the projected cycles for 80 years remain less than 7,000 cycles. Table 4.3.3-1, "80 Year Transient-Cycle Projections for Non-Class 1 Piping," and WCAP-18772-NP, "Resolution of Virgil C. Summer Nuclear Station Time-Limited Aging Analyses for Subsequent License Renewal," (Reference 4.8-1) provide the basis for concluding that the number of cycles for each of these piping systems is projected to be less than 7,000. Therefore, the ASME Code, Section III (Subsections NC and ND) and ANSI B31.1 allowable stress analyses remain valid for the subsequent period of extended operation.

Initial license renewal validated that the Non-Class 1 piping would receive less than 7,000 cycles. For subsequent license renewal, it is confirmed that the Non-Class 1 piping is projected to receive less than 7,000 cycles.

In addition, no component in the systems identified by Table 4.3.3-1 were designed in accordance with ASME Code, Section VIII, Division 2.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The Non-Class 1 allowable-stress analyses remain valid for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

Table 4.3.3-1 80 Year Transient-Cycle Projections for Non-Class 1 Piping

Description	Conservative Basis for Cycle Projection	Projected Cycles for 80 Years
Auxiliary Boiler Steam and Feedwater (AS)	20 cycles per year - 1600 cycles	Less than 2000 cycles
Steam Generator Blowdown (BD)	10 cycles per year - 800 cycles	Less than 1000 cycles
Boron Recycle (BR) and Radwaste Liquid Handling (WL)	20 cycles per year - 1600 cycles	Less than 2000 cycles
Chemical and Volume Control (CS) and Chemical and Volume Control Vents and Drains (CV)	20 cycles per year - 1600 cycles	Less than 2000 cycles
Diesel Generator Services (DG)	30 cycles per year - 2400 cycles	Less than 3000 cycles
Emergency Feedwater (EF)	20 cycles per year - 1600 cycles	Less than 2000 cycles
Extraction Steam (EX)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1	Less than 7000 cycles
Feedwater (FW)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1	Less than 7000 cycles
Gland Sealing Steam (GS)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1	Less than 7000 cycles
Main Steam Dump (MB)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1	Less than 7000 cycles
Main Steam (MS)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1	Less than 7000 cycles

Table 4.3.3-1 80 Year Transient-Cycle Projections for Non-Class 1 Piping

Description	Conservative Basis for Cycle Projection	Projected Cycles for 80 Years
Reactor Coolant (RC)	RCS transients from Table 4.3.1-1	Less than 7000 cycles
Residual Heat (RH)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1	Less than 7000 cycles
Safety Injection (SI)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1	Less than 7000 cycles
Nuclear Sampling (SS)	RH Loop 10 cycles per year - 800 cycles	Less than 1000 cycles
	Pressurizer Liquid and Steam Spaces 10 cycles per year - 800 cycles	Less than 1000 cycles
	RCS ‘B’ and ‘C’ Hot Legs The number of cycles through 60 years of operation is conservatively estimated to be 6668 cycles based on historical sampling from the RCS ‘B’ hot leg. However, routine samples are no longer taken directly from the ‘B’ hot leg. Samples are now routinely taken downstream from the letdown heat exchanger where the process temperature is below the threshold temperature for thermal fatigue.To bound thermal cycling resulting from sampling either the ‘B’ or the ‘C’ reactor coolant loops and to include quarterly cycling of CIVs, a conservative assumption of 10 thermal cycles per year is assumed for an additional 20 years. This results in a conservative estimate of 6868 cycles for 80 years.	Less than 7000 cycles
	Steam Generator Blowdown/Drum 10 cycles per year - 800 cycles	Less than 1000 cycles
Turbine Cycling Sampling (WA)	10 cycles per year - 800 cycles	Less than 1000 cycles

4.3.4 ENVIRONMENTALLY-ASSISTED FATIGUE

TLAA Description:

In support of initial license renewal, environmentally-assisted fatigue (EAF) analyses were prepared for limiting locations within the Class 1 piping systems and for ASME Code, Section III, Class 1 components that contact reactor coolant. These EAF analyses were developed to account for environmental effects on these systems and components for the initial period of extended operation. Since these analyses were based on transient cycles for the initial license renewal period, they have been identified as TLAAs that require evaluation for the subsequent period of extended operation.

TLAA Evaluation:

For subsequent license renewal, environmentally-assisted fatigue (EAF) was evaluated consistent with NUREG-2191, Section X.M1 (Reference 1.7-6) and Section 4.3 of NUREG-2192 (Reference 1.7-5). The effects of the reactor water environment on CUF were examined for a set of sample critical components for the plant, including the locations identified in NUREG/CR-6260 (Reference 4.8-39) and additional plant-specific component locations in the reactor coolant pressure boundary that were identified through an environmentally-assisted fatigue (EAF) screening evaluation. The EAF screening process evaluated existing fatigue usage values for the ASME Code, Section III components and piping, including the NUREG/CR-6260 locations, to determine the sentinel locations for EAF.

To support subsequent license renewal, 80-year EAF evaluations were prepared using 40-year design transients for the ASME Code, Section III, pressure boundary components, and Class 1 piping (greater than one-inch diameter out to the second isolation valve) that contact the reactor coolant fluid. Table 4.3.1-1, 80-Year Transient-Cycle Projections, demonstrates that the 40-year design transients bound the 80-year transient-cycle projections. The limiting locations were determined by identifying the fatigue-sensitive locations, followed by comparison and ranking. The screening process used multiple steps, as described below. As a result of the screening evaluation, there were other locations identified that are more limiting than the NUREG/CR-6260 locations.

A consolidated tabulation for ASME Code, Section III, pressure boundary components and piping is presented for the sentinel locations in Table 4.3.4-1, Summary of Equipment and Piping Sentinel Locations Requiring EAF Evaluations. These 80-year evaluations are for subsequent license renewal purposes and do not amend the existing design reports.

<u>ASME Code, Section III, Class 1 Components and Piping</u>

The nuclear steam system supplier (NSSS) vendor performed the EAF screening for the Class 1 equipment, main loop piping, and Class 1 auxiliary piping locations to provide a comprehensive list of sentinel locations. Applicable ASME Code, Section III, Class 1 components and piping that are susceptible to EAF were reviewed and categorized into common systems, or transient sections.

Screening F_{en} factors were developed so that environmentally-adjusted cumulative usage factor (CUF_{en}) values could be calculated for each component and piping system, which were then compared to determine limiting locations. The methodology outlined in NUREG/CR-6909, Revision 1 (Reference 4.8-41) is used for stainless steels, carbon and low-alloys steels, and Ni-Cr-Fe alloys. The initial EAF screening results for sentinel locations are based upon the most-conservative F_{en} values from NUREG/CR-6909, Revision 1.

Conservative values were chosen for each of the F_{en} input parameters: sulfur content, service temperature, strain rate, and dissolved oxygen (DO). The reactor coolant system DO content is procedurally controlled by the Water Chemistry program (B2.1.2).

For the systems where the NUREG/CR-6260 locations have the highest screening CUF_{en} value, no additional locations were considered as sentinel locations. For those systems where the NUREG/CR-6260 locations do not have the highest screening CUF_{en} value, or where a NUREG/CR-6260 location does not exist, the location within that transient section that has the highest screening CUF_{en} value in excess of 1.0 is the EAF sentinel location. The final set of sentinel locations is meant to supplement those identified in NUREG/CR-6260, resulting in a comprehensive list of plant-specific, primary-equipment and piping sentinel locations for EAF consideration.

Any location that was not part of the ASME Code, Section III, reactor-coolant pressure boundary was removed from consideration. Locations not in contact with primary coolant were also excluded. Candidate sentinel locations for ASME Code, Section III components and piping were identified, ranked, and evaluated as described below:

- Components and piping with a screening CUF_{en} value of less than 1.0 were removed, except for the NUREG-6260 locations.
- Stress-basis analysis ranking was used to assess the level of technical rigor of the analysis for each component and piping location within the transient section.
- Within each transient section, the location with the maximum screening CUF_{en} value for each applicable material type was retained.
- For some of the ASME Code, Section III components and piping with initial CUF_{en} values greater than 1.0 (when using the 40-year design transients as input into the CUF_{en} calculations), updated calculations prepared in accordance with ASME Code, Section III, Subsection NB-3200, were used to remove conservatism in the design CUF analysis, thereby reducing the CUF_{en} to less than 1.0.
- The candidate sentinel locations were compared to any NUREG/CR-6260 locations within the transient section. Component locations with a CUF_{en} value lower than the CUF_{en} value of the NUREG/CR-6260 location were removed from the final set of sentinel locations.

The criteria listed above were used to determine the final sentinel locations, which are summarized in Table 4.3.4-1, Summary of Equipment and Piping Sentinel Locations Requiring EAF Evaluations. Locations with CUF_{en} values greater than 1.0 or with CUF_{en} values greater than that for the applicable NUREG/CR-6260 location required more-detailed analysis, monitoring, or inspection. These locations have bounding CUF_{en} values compared with other locations within the same transient section.

As shown in Table 4.3.4-1, the CUF_{en} values for the RV shell-to-inlet nozzles, RV main shell, safety injection cold leg nozzles and residual heat removal hot leg nozzles are less than 1.0. Therefore, fatigue management is not required for these transient sections and associated components.

Except for the steam generator tubing, which is managed by the Steam Generators program (B2.1.10), the remaining sentinel locations in Table 4.3.4-1 have been analyzed using a flaw-tolerance evaluation, and EAF for these components will be managed by application of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) for the subsequent period of extended operation.

Fatigue Management

NUREG-2191 (X.M1) and NUREG-2192 permit inservice inspections as a management method for EAF, so long as a flaw-tolerance evaluation, conducted in accordance with the guidance of ASME Code, Section XI, Nonmandatory Appendix A or Appendix L, is performed, in conjunction with calculated allowable-flaw sizes, to determine the acceptable time between inspections at the bounding location. The ASME Code, Section XI, Appendix A and Appendix L flaw-tolerance evaluations consist of postulating hypothetical inside-surface axial and circumferential flaws. For a postulated initial flaw, crack growth is simulated, based upon exposure to specified numbers of transient cycles, until the flaw has reached the allowable-flaw depth or the end of the subsequent period of extended operation, whichever comes first.

For the sentinel-component locations where the CUF_{en} values were not reduced to less than 1.0 using ASME Code, Section III, Subsection NB-3200 calculations, a flaw-tolerance evaluation was generated.

The ASME Code, Section XI, Appendix A flaw-tolerance evaluation of the RV shell-to-outlet nozzle welds shows a final flaw size of 0.3576 inches, compared to the allowable end-of-evaluation flaw size of 0.696 inches, which equates to an allowable operating period of 80 years. The effects of environmental fatigue for the RV shell-to-outlet nozzle weld will be managed by application of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) for the subsequent period of extended operation, based upon the results of the flaw-tolerance evaluation.

Two sentinel piping locations have been analyzed using ASME Code, Section XI, Appendix L and the results are presented in Table 4.3.4-2, ASME Code, Section XI, Appendix L Results. For these two sentinel piping locations, the normal/alternate charging cold leg nozzles and the pressurizer surge line hot leg nozzle, flaw-tolerance evaluations were generated.

In accordance with ASME Code, Section XI, Article L-2010(c), “the loading in the design specification, plant-specific loading cycles consistent with the plant design and operating practices, or actual plant operating data, shall be used, as appropriate.” The transients used to simulate growth of the postulated flaws in the ASME Code, Section XI, Appendix L evaluation fall into two categories. The first group of transients is associated with the operation of the plant. The second group of transients is associated with design of the plant. The transients used to simulate growth of the postulated flaws in the ASME Code, Section XI, Appendix L evaluations were based upon rates of cycle occurrence intended to be conservative for ten years of operation. Conservative rates of cycle occurrence were used to evaluate 80 years of plant operation. The combined selection of transients and inspection frequency is very conservative, thereby ensuring the inspection frequencies remain adequate.

The maximum allowable end-of-evaluation-period flaw size was determined based on the acceptance criteria and evaluation procedures in ASME Code, Section XI, Appendix C, 2017 Edition, which is the current code of record. Based on previous inspection records, there are no recordable indications in the normal/alternate charging system or pressurizer surge-line piping. Therefore, the methodology of ASME Code, Section XI, Appendix L may be used. The piping systems evaluated here are constructed from stainless steel material, where the only significant crack-growth mechanism of consideration is fatigue crack growth (FCG). As per ASME Code, Section XI, Appendix L, an initial postulated flaw size based on ASME Code, Section XI acceptance standards in Table IWB-3514-2 (with aspect ratio of 6) was used in the FCG analysis. The transients used in the flaw-tolerance evaluations performed under ASME Code, Section XI, Appendix L, are a subset of the transients listed in FSAR Table 5.2-2, which are monitored under the Fatigue Monitoring program (B3.1).

Based on the FCG evaluation, the allowable operating period was determined to be the length of time it takes for the postulated initial flaw to grow to the maximum allowable end-of-evaluation-period flaw size. The fatigue-crack-growth analyses were completed using the crack-growth rates from ASME Code, Section XI, Code Case N-809, “Reference Fatigue Crack Growth Rate Curves for Austenitic Stainless Steels in Pressurized Water Reactor Environments, Section XI, Division 1, ASME International” (Reference 4.8-43). The results of the ASME Code, Section XI, Appendix L analyses are provided in Table 4.3.4-2 and WCAP-18790-P (Reference 4.8-42). The ASME Code, Section XI, Appendix L inspections are identified in Table 4.3.4-3, Appendix L Inspections.

Following re-inspection, when no relevant indication (NRI) is identified, the cycle counts used in the ASME Code, Section XI, Appendix L evaluation are reset to zero for the next successive inspection interval. This is justified because the successful inspection validated the assumption used in the flaw-tolerance evaluation that no measurable flaw exists in the component, and the flaw-tolerance evaluation demonstrates that even if the postulated flaw does exist, it will not reach the maximum allowable flaw size prior to re-inspection.

The effects of EAF on the components listed below will be by managed by application of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) during the subsequent period of extended operation.

- Normal and alternate charging cold leg nozzles (Appendix L flaw-tolerance evaluation)
- Pressurizer surge line hot leg nozzle (Appendix L flaw-tolerance evaluation)

Each of the Appendix L flaw-tolerance evaluations for the above components demonstrates that a flaw will not reach the critical flaw size before the next ISI inspection.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging due to EAF on the intended function(s) of the ASME Code, Section III, Class 1 components and ASME Code, Section III, Class 1 piping, that has been analyzed with ASME Code, Section XI, Appendix A or L evaluations, will be adequately managed by application of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1), The Fatigue Monitoring program (B3.1) monitors and tracks the number of occurrences of each of the critical thermal and pressure transients that are used in the Appendix A and Appendix L flaw-tolerance evaluations to verify the numbers of cycles do not exceed the numbers of analyzed cycles and to validate that the inspection frequencies remain appropriate.

Thus, the effects of aging due to EAF on the intended function(s) will be adequately managed for the subsequent period of extended operation and the EAF TLAAs for these components are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

The Steam Generators program (B2.1.10) manages aging of the steam generator tubing.

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Table 4.3.4-1 Summary of Equipment and Piping Sentinel Locations Requiring EAF Evaluations

Transient Sections[j]	Sentinel Location *(VCSNS Location)*	Material	AOR CUF	SLR CUF	F_{en}[a]	CUF_{en}[b][d]	Analysis Method[c]	EAF Management Method
Reactor Vessel	RV Outlet Nozzles and Support Pads *(RV shell-to-outlet nozzles)*	LAS	0.293	2.930	6.276	>1.0	NUREG/CR-6260 Location ASME Code, Section XI, Appendix A Flaw Tolerance Evaluation (PWROG-17031-NP-A Rev. 1)	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) Time Between Inspections: 80 yrs.[e]
	RV Inlet Nozzle and Support Pads *(RV shell-to-inlet nozzles)*	LAS	0.163	0.073	6.276	0.458	NUREG/CR-6260 Location ASME Code, Section III, Subsection NB-3200 (CUF_{en} < 1.0)	None Required[f]
	RV Shell Transition *(RV main shell)*	LAS	0.010	0.010	6.276	0.063	NUREG/CR-6260 Location ASME Code, Section III, Subsection NB-3200 (CUF_{en} < 1.0)	None Required[f]
Steam Generator	Tubes	Ni-Cr-Fe Alloy	0.396	3.960[i]	3.746	>1.0	Not a NUREG/CR-6260 Location ASME Code, Section III, Subsection NB-3200	Steam Generators program (B2.1.10)[g]

Table 4.3.4-1 Summary of Equipment and Piping Sentinel Locations Requiring EAF Evaluations

Transient Sections[j]	Sentinel Location *(VCSNS Location)*	Material	AOR CUF	SLR CUF	F_{en}[a]	CUF_{en}[b][d]	Analysis Method[c]	EAF Management Method
Section 1 Safety Injection	SI Cold Leg Nozzles *(Safety injection cold leg nozzles)* 6-inch Sch 160 RCL Crotch at 45°	SS	0.960	0.090	8.996	0.812	NUREG/CR-6260 Location ASME Code, Section III, Subsection NB-3200 (CUF_{en} <1.0)	None Required
Section 2 Residual Heat Removal	RHR Hot Leg Nozzles *(Residual heat removal hot leg nozzles)* 6-inch Sch. 160 RCL Crotch at 0°	SS	0.264	0.038	22.78	0.854	NUREG/CR-6260 Location ASME Code, Section III, Subsection NB-3200 (CUFen < 1.0)	None Required

Table 4.3.4-1 Summary of Equipment and Piping Sentinel Locations Requiring EAF Evaluations

Transient Sections[j]	Sentinel Location *(VCSNS Location)*	Material	AOR CUF	SLR CUF	F_{en}[a]	CUF_{en}[b][d]	Analysis Method[c]	EAF Management Method
Section 3 Charging (Normal and Alternate)	Charging Cold Leg Nozzles *(Normal / alternate charging cold leg nozzles)* 3-inch Sch. 160 RCL	SS	0.900	9.000 [i]	12.81	>1.0	NUREG/CR-6260 Location (ASME Code, Section XI, Appendix L)[h]	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) Time Between Inspections: >80 yrs.
Section 5 Pressurizer Lower Head and Pressurizer Surge Line	Pressurizer Surge Line Hot Leg Nozzle[k] *(Pressurizer surge line hot leg nozzle)* 14-inch Sch. 160 RCL	SS	0.360	3.60 [i]	12.810	>1.0	NUREG/CR-6260 Location (ASME Code, Section XI, Appendix L)[h]	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) Time Between Inspections: 48 yrs.

Footnote(s)

(a) The F_{en} documented in this table is a factor that accounts for the environmental effects on metal exposed to primary side water chemistry.

(b) For major component EAF screening, the methodology in NUREG/CR-6909, Revision 1 (Reference 4.8-41) is used for all material types. For piping EAF screening, the methodology in NUREG/CR-6909, Revision 1 is used for all material types.

(c) The NUREG/CR-6260 (Reference 4.8-39) locations are retained as sentinel locations.

(d) The CUF_{en} values for these major components are documented in WCAP-18772-NP (Reference 4.8-1).

(e) The time between inspections for the RV shell-to-outlet nozzles is 80 years for EAF. However, the ISI program requires these components to be inspected on a 20-year frequency.

(f) CUF_{en} less than 1.0. No fatigue management required per NUREG-2191. The Fatigue Monitoring program (B3.1) monitors transients for this location.

(g) The steam generator tubes are examined by eddy-current testing.

(h) A flaw-tolerance evaluation for the charging nozzles and pressurizer surge line hot leg nozzle is included in WCAP-18790-P (Reference 4.8-42).

(i) The F_{en} values for these locations applied an F_{adj}=10.0 multiplier as documented in WCAP-18772-P (Reference 4.8-2).

(j) No sentinel locations were identified in transient section 4 – Letdown (Normal Letdown, Excess Letdown, Loop Drain), transient section 6 – Pressurizer Upper Head and Shell, and transient section 7 – Pressurizer Safety and Relief Lines, as all CUF_{en} values are less than 1.0 and less than all the CUF_{en} values for the NUREG/CR-6260 locations.

(k) Per NUREG-1766 (Reference 4.8-13), the surge line hot leg nozzle is identified as the most limiting component associated with the pressurizer.

Table 4.3.4-2 ASME Code, Section XI, Appendix L Results

Auxiliary Line Nozzle to Pipe Weld	Flaw Configuration	Aspect Ratio[(a)]	Initial Flaw Size (a/t)[(b)]	Final Flaw Size (a/t)[(c)]	Maximum Allowable End-Of- Flaw size (a/t)[(d)]	Allowable Operating Period (Years)[(e)]
Normal / Alternate Charging Cold Leg Nozzles 3-inch RCL	Axial	11	0.1227	0.127	0.510	>80
	Circumferential	Continuous 360°	0.1227	0.126	0.290	>80
Pressurizer Surge Line Hot Leg Nozzle 4-inch RCL	Axial	9	0.11007	0.131	0.560	>80
	Circumferential	6	0.11007	0.468	0.470	48

Footnote(s):

(a) Aspect Ratio (AR), defined as flaw length over flaw depth, is assumed to stay constant as the crack grows through the wall thickness.

(b) Initial postulated flaw size, which is based on ASME Code, Section XI, Table IWB-3514-1 and Table IWB-3514-2 for an aspect ratio of 6. The methodology of the initial flaw size is based on ASME Code, Section XI Appendix L-3210.

(c) The final flaw size is based on fatigue-crack growth per ASME Code Case N-809 with a constant aspect ratio. The aspect ratio for the FCG evaluation is determined per ASME Code, Section XI Appendix L.

(d) The maximum allowable end-of-evaluation flaw size is determined per ASME Code, Section XI Appendix C. The final flaw size after fatigue-crack growth should be equal to or less than the maximum allowable end-of-evaluation flaw size.

(e) The allowable operating period represents the number of years (i.e., re-inspection interval) required for the initial flaw size to reach the maximum allowable end-of-evaluation flaw size. In cases where the allowable operating period is reported to be greater than 80 years, it should be noted that the final flaw size, after fatigue-crack growth, never reached the end-of-evaluation flaw size during a maximum of 80 years of plant operation.

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Table 4.3.4-3 Appendix L Inspections

Location	Weld No.	Last ISI Inspection
Normal Charging Line	CGE-1-4200-22BC	10/27/2015
Alternate Charging Line	CGE-1-4100-26BC	10/26/2015
Pressurizer Surge Line	CGE-1-4100-19BC	06/21/1993

4.3.5 HIGH-ENERGY LINE BREAK ANALYSIS

TLAA Description:

As stated in Table 4.1-2 of NUREG-2192 (Reference 1.7-5), a high-energy line-break (HELB) analysis is considered one of the potential TLAAs for consideration when assessing the subsequent period of extended operation. As indicated in FSAR Section 3.6.2 (Reference 1.7-18), high-energy systems that require analysis for the consequences of pipe break were identified based on the fluid in the pipe, the pressure, and the temperature during normal station operation. The lines that were both high-temperature and high-pressure were postulated to experience a longitudinal or circumferential break, and were analyzed for pipe whip, jet impingement, and environmental effects. A HELB is not required to be postulated at a given piping location if the design CUF calculated in accordance with ASME Code, Section III for that location is less than or equal to 0.1. Therefore, these evaluations excluded locations within each high-energy piping system that have a CUF value of 0.1 or less, the HELB screening criterion is specified in FSAR Section 3.6.2.1.2, "High Energy System Piping Inside Containment."

Now that plant operation will be extended through 80 years, it is possible that one or more of these locations could see an increase in fatigue usage, potentially above 0.1, that would require the location to be evaluated as a potential break location. Since the ASME Code, Section III, Class 1 piping fatigue analyses that provided the CUF values less than 0.1 are based upon 40-year design transients, these analyses have been identified as TLAAs that require evaluation for subsequent license renewal. The HELB evaluations for the ASME Code, Section III, Class 2 and 3 piping do not involve a time-limited assumption and are not identified as TLAAs.

TLAA Evaluation:

The CUF analyses for the high-energy piping systems were developed in accordance with the requirements of the ASME Code, Section III rules (i.e., NB-3222.4(e)), based upon the 40-year design transients listed in Table 4.3.1-1. Existing TLAAs for the Class 1 piping locations were reviewed to compare the applicable transients and cycles with the 80-year transient cycle projections. The 80-year transient cycle projections for each of the transients applicable to the Class 1 piping components under investigation is consistent with the transients identified for subsequent license renewal.

The 40-year design transient cycles analyzed in the ASME Code, Section III fatigue analyses of record for the ASME Class 1 piping bound the projected 80-year transient cycles, as shown in Table 4.3.1-1. The CUF values will remain less than 1.0 for all locations and no CUF values increase. Therefore, the original HELB locations identified through the HELB screening process remain unchanged and no new HELB locations must be postulated for the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The current HELB analyses remain valid for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

TLAA Description:

Thermal, radiation, and cyclical aging analyses of plant electrical and I&C equipment, developed to meet 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants,” (Reference 1.7-8) requirements, have been identified as TLAAs. The environmental qualification (EQ) requirements in Title 10 of the Code of Federal Regulations (10 CFR) 50.49 require that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments is qualified to perform applicable safety functions in those harsh environments after the effects of in-service aging. Harsh environments are defined as 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), or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

Environmental Qualification Program Background

10 CFR 50.49 requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform its safety function in those harsh environments after the effects of in-service aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification. Aging evaluations that qualify equipment to at least the end of the current licensed operating period are TLAAs.

10 CFR 50.49 defines the scope of equipment to be included and requires the preparation and maintenance of documentation that includes equipment performance specifications, electrical characteristics, and environmental conditions. 10 CFR 50.49 (e)(5) contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect equipment functional capability. 10 CFR 50.49 (e)(5) also requires equipment replacement prior to the end of designated life, unless additional life is established through ongoing qualification.

V. C. Summer Nuclear Station received an operating license in November 1982. The basis for Equipment Qualification for the original plant design is IEEE 323-1971, “General Guide for Qualifying Class 1E Electrical Equipment for Nuclear Power Generating Stations,” (Reference 4.8-44) and NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment,” (Reference 4.8-46) Category II requirements, as codified by 10 CFR 50.49. However, some equipment was qualified to IEEE 323-1974, “IEEE Standard for Qualifying Class IE Equipment for Nuclear Power Generating Stations,” (Reference 4.8-45) NUREG-0588 Category I requirements. Electrical equipment for replacements or modifications to the plant is procured under the guidance of 10 CFR 50.49 and is qualified under the requirements of IEEE 323-1974 and NRC Regulatory Guide (RG) 1.89. IEEE 323-1974, “IEEE Standard for

Qualifying Class IE Equipment for Nuclear Power Generating Stations," provides the criteria for safety-related equipment (electrical "Class 1E" equipment) and the basis for categorizing components important to safety and defines environmental service conditions. Therefore, the EQ program includes and identifies electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49.

As required by 10 CFR 50.49, EQ equipment not qualified for the current license term is refurbished or replaced, or has its qualified life extended through reanalysis or ongoing qualification prior to reaching the designated life aging limits established in the evaluation. Aging evaluations for EQ equipment that specify a qualified life of at least 40 to 60 years are 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 the 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).

TLAA Evaluation:

The EQ program implements the requirements of 10 CFR 50.49, as further defined, and clarified by NUREG-0588 Category II requirements. The basis for Equipment Qualification for the original plant design is IEEE 323-1971 "General Guide for Qualifying Class 1E Electrical Equipment for Nuclear Power Generating Stations," as codified by 10 CFR 50.49. However, some equipment was qualified to IEEE 323-1974 "IEEE Standard for Qualifying Class IE Equipment for Nuclear Power Generating Stations," NUREG-0588 Category I requirements. The EQ program is viewed as an aging management program for license renewal under 10 CFR 54.3(a).

Reanalysis of an aging evaluation to extend the qualified life of equipment is performed as part of the EQ program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, corrective actions (if acceptance criteria are not met), and ongoing qualification and are addressed below. TLAA demonstration option (iii), which states that the effects of aging will be adequately managed for the period of extended operation, is chosen and the EQ program will manage the aging effects of equipment associated with the environmental qualification TLAA.

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. An acceptable method for establishing the 80-year normal radiation dose is to multiply the 40-year normal radiation dose by 2, with the result being added to the accident radiation dose to obtain the total integrated dose for the component. A similar approach may be used for cyclical aging.

Data Collection and Reduction Methods

The identification of excess conservatism in electrical equipment service conditions (for example, temperature, radiation, and cycles) used in the prior aging evaluation is the primary method used for a reanalysis. Temperature data and uncertainties used in an equipment EQ evaluation should be based on plant design temperatures or on actual plant temperature data. A representative number of temperature measurements over a sufficient period are evaluated to establish the temperatures used in an aging evaluation. Similar methods of identifying excess conservatism in the equipment service condition evaluation may 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. Although areas within a nuclear power plant may experience actual ambient environments that are less severe than the anticipated plant design environment, in a limited number of localized areas, the actual environments may be more severe than the plant design environment considered for EQ equipment. These adverse localized environments (ALE) are addressed in an EQ reanalysis.

Acceptance Criteria and Corrective Actions

Reanalysis of an aging evaluation can be used to extend the environmental qualification of the equipment. If the qualification cannot be extended by reanalysis, the equipment is refurbished, replaced, or re-qualified prior to exceeding the current qualified life.

A reanalysis should be performed in a timely manner such that sufficient time is available to refurbish, replace, or re-qualify the equipment if the reanalysis is unfavorable. 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 aging evaluation.

Ongoing Qualification

When the reanalysis assessed margins, conservatisms, or assumptions do not support reanalysis (e.g., extending qualified life) of EQ equipment, the use of ongoing 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. 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.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging on the intended function(s) of EQ components that are the subject of EQ TLAAs will be adequately managed by the *Environmental Qualification of Electric Equipment* program (B3.3) for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

4.5 CONCRETE CONTAINMENT TENDON PRESTRESS ANALYSIS

NOTE: Reactor Building is the site-specific term used for Containment; therefore, these terms are interchangeable.

TLAA Description

Original Construction

Containment is provided by the Reactor Building; a post-tensioned, reinforced-concrete structure composed of vertical cylinder walls and a shallow dome on a reinforced-concrete base slab. The post-tensioning system consists of dome tendons, hoop tendons, and vertical tendons. The cylinder walls are provided with 115 vertical tendons and 150 horizontal hoop tendons. The dome is provided with three layers of 33 tendons for a total of 99 tendons that intersect at 60^{o}.

The tendon prestressing forces were calculated during the original design and took into consideration the magnitude of tendon relaxation and concrete creep and shrinkage projected to occur over the 40-year life of the plant. The prestress of tendons decreases over time due to seating of anchorage losses, elastic shortening of concrete, creep of concrete, shrinkage of concrete, relaxation of prestressing steel, and friction losses. At the time of initial licensing, the magnitude of the prestress losses throughout the life of the plant was predicted and the estimated final effective preload at the end of 40 years was calculated for each tendon type based on log-linear extrapolation of creep, shrinkage, and relaxation results. The final effective preload was then compared with the minimum-required preload to confirm the adequacy of the design.

Early Plant Operation

Individual Predicted Lower Limit (PLL) values were developed during design and construction of the Reactor Building and later incorporated uncertainty adjustments consistent with NRC Regulatory Guide (RG) 1.35.1 (Reference 4.8-35).

Following the 10-year surveillance, conducted in 1990, the vertical-tendon-group mean-force trend showed that the mean could fall below the 1,160-kip acceptance limit prior to completion of the 15-year surveillance. Therefore, to ensure continuing structural integrity of the Reactor Building, all vertical tendons were re-tensioned after the 10-year surveillance.

Current Operation

The ASME Section XI, Subsection IWL program (B2.1.31) performs periodic surveillances of individual tendon prestressing values.

Predicted force values are calculated for each individual tendon prior to the surveillances to estimate the magnitude of the tendon relaxation and concrete creep and shrinkage for the given surveillance period. The prestressing forces are measured and plotted, and trend lines are developed, to ensure the mean-tendon-group prestressing values remain above the respective minimum-required values (MRVs) until the next scheduled surveillance. The trend lines are periodically updated with new tendon prestressing force data following each surveillance. The trend lines are used to demonstrate that the mean-group prestressing forces will remain above the group minimum-required value until the next scheduled surveillance. The most recent tendon surveillance projected the estimated final effective prestressing force to 60 years to confirm tendon trend lines remain above the minimum-required tendon forces for containment tendons.

The predicted force values and regression analyses, utilizing actual measured tendon forces, are used to evaluate the acceptability of the containment structure to perform its intended function over the current 60-year life of the plant, and therefore, have been identified as TLAAs requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation

The Concrete Containment Unbonded Tendon Prestress program (B3.4) is a confirmatory program that monitors the loss of tendon-prestressing forces throughout the life of the plant, including the subsequent period of extended operation. This program consists of an assessment of the results of the tendon-prestressing force measurements performed in accordance with the ASME Section XI, Subsection IWL program (B2.1.31).

As part of the program, tendon forces are periodically measured for selected tendons. Regression analyses are performed to obtain the trendlines which fit the measured tendon force data most accurately in order to forecast the tendon forces for the subsequent period of extended operation. Trend-line regression analysis is performed consistent with NRC Information Notice 99-10 (IN 99-10), “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments,” for each tendon group. Detensioned and/or retensioned tendons are no longer considered to be statistically relevant to the original tendon population and are excluded from the regression analysis.

Predicted-lower-limit lines and trend lines of measured prestressing forces have been established for applicable tendon groups through the subsequent period of extended operation. The PLL lines for each tendon group incorporated uncertainty adjustments consistent with Regulatory Guide 1.35.1. For each tendon group, the individual measured tendon force data, the trendlines obtained from regression analyses of the individual measured tendon force data, the PLL values for a tendon group, and the current minimum-required tendon forces are plotted in log-linear time-force plots for the subsequent period of extended operation, which corresponds to about 81.6 years after initial prestressing of the tendons.

Figure 4.5-1 is a plot showing hoop tendon forces measured during all surveillances conducted to date (through the 2020 surveillance), the measured-force trend line, the PLL line, and an acceptance limit at F (tendon-group mean force) = 1,000 kip, the minimum-required value of the group mean force. The measured-force trend line, which is representative of group-mean force, remains above the 1,000-kip minimum-required value throughout the subsequent period of extended operation. The trend line also remains above the PLL throughout the subsequent period of extended operation.

Figure 4.5-2 is a plot showing vertical tendon forces measured during all surveillances from 1996 through 2020, the measured-force trend line, the PLL line and an acceptance line at F = 1,160 kip, the minimum-required value of the group-mean force. As all vertical tendons were re-tensioned in 1990 following the surveillance performed that year, forces measured during this and earlier surveillances have no effect on the current performance of the group. The trend line, which is representative of group-mean force, remains above the 1,160-kip minimum-required value throughout the subsequent period of extended operation. The trend line also remains above the PLL throughout the subsequent period of extended operation.

Figure 4.5-3 is a plot showing dome tendon forces measured during all surveillances conducted to date through the 2020 surveillance, the measured-force trend line, the PLL line, and an acceptance line at F = 1,025 kip, the minimum-required value of the group mean force. The measured-force trend line, which is representative of group-mean force, remains above the 1,025-kip minimum-required value throughout the subsequent period of extended operation. The trend line also remains above the PLL, which crosses the minimum-required value line at T = 77.8 years. While the PLL crosses the lower limit prior to end of the subsequent period of extended operation, this has no impact on conclusions regarding future prestressing forces as these are based on actual system performance. Corrective actions will be completed if the measured-force trend lines predict the prestressing forces in the tendon group to be below the MRV before the next scheduled examination.

As shown in Figure 4.5-1 through Figure 4.5-3, the trendlines developed using past surveillance data remain above the current minimum-required tendon force curves for all dome, hoop, and vertical tendons during the entire subsequent period of extended operation.

Table 4.5-1 provides a summary of the forecasted tendon forces and concludes all mean-force trendlines for the 60-year initial period of extended operation and 80-year subsequent period of extended operation are higher than the minimum-required tendon forces. The 60-year initial period of extended operation corresponds to about 61.6 years after initial prestressing of the tendons and the 80-year subsequent period of extended operation corresponds to about 81.6 years after initial prestressing of the tendons. Therefore, pre-stressing forces are expected to remain above the MRVs throughout both the initial and subsequent periods of extended operation.

With one exception, Table 4.5-1 PLL values are also forecast to remain above the respective MRVs at T = 81.6 years. The exception is the dome tendon PLL which falls 1 kip below the MRV at the end of the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging related to prestress forces on the intended function(s) of the containment tendon prestressing system will be adequately managed by the Concrete Containment Unbonded Tendon Prestress program (B3.4) and ASME Section XI, Subsection IWL program (B2.1.31) for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

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Figure 4.5-1 Hoop Tendon Force Trend and PLL

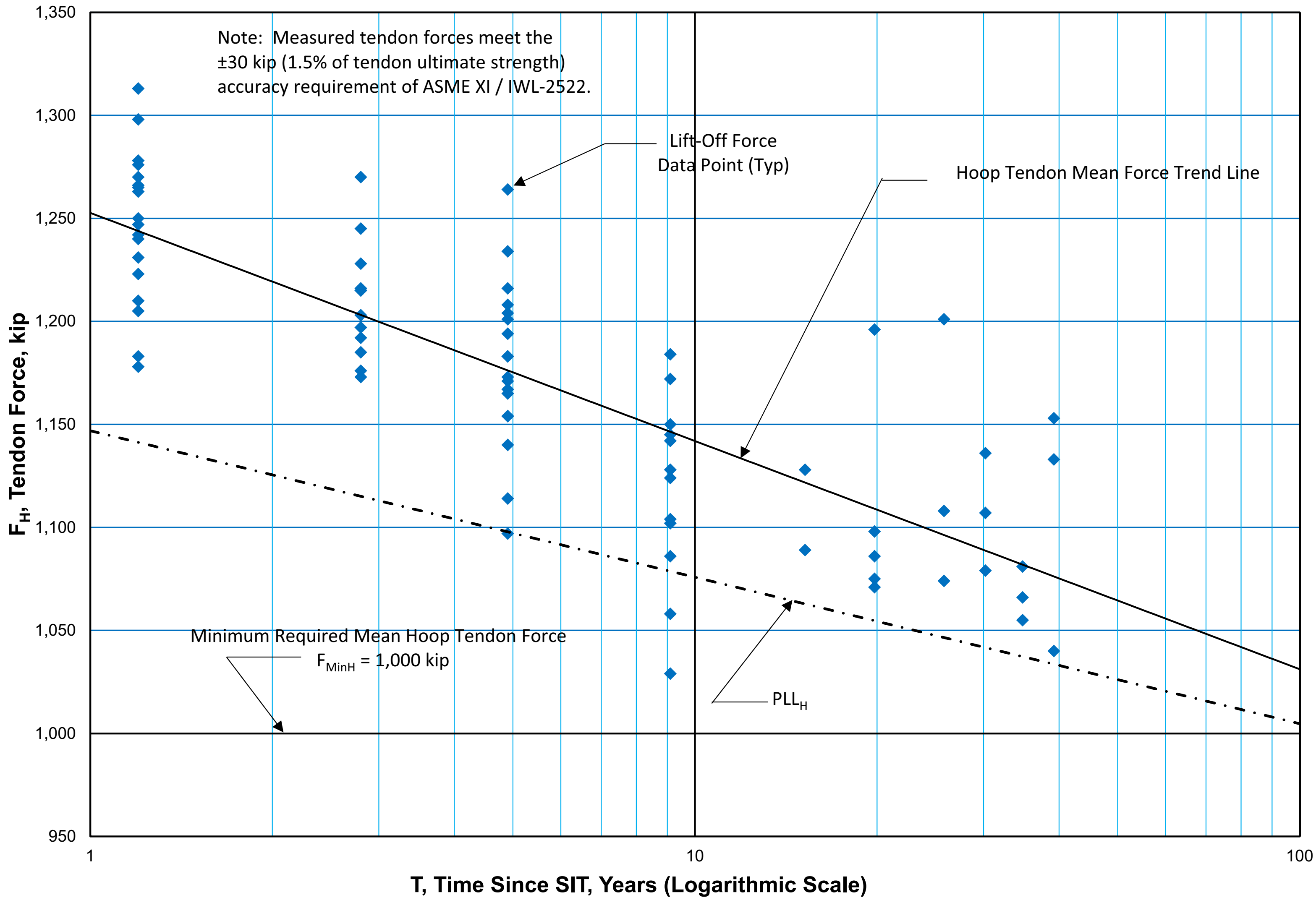

Figure 4.5-2 Vertical Tendon Force Trend and PLL

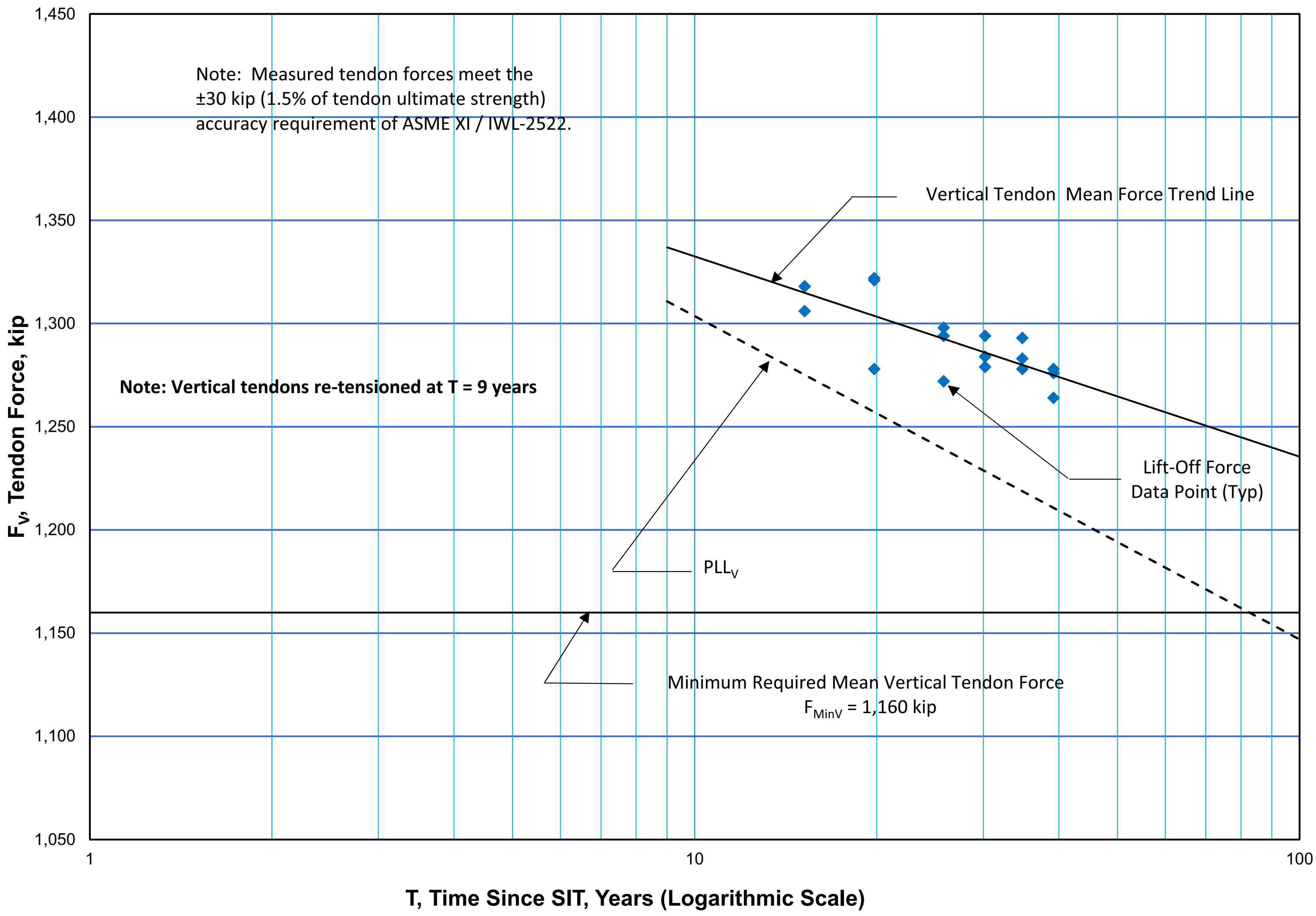

Figure 4.5-3 Dome Tendon Force Trend and PLL

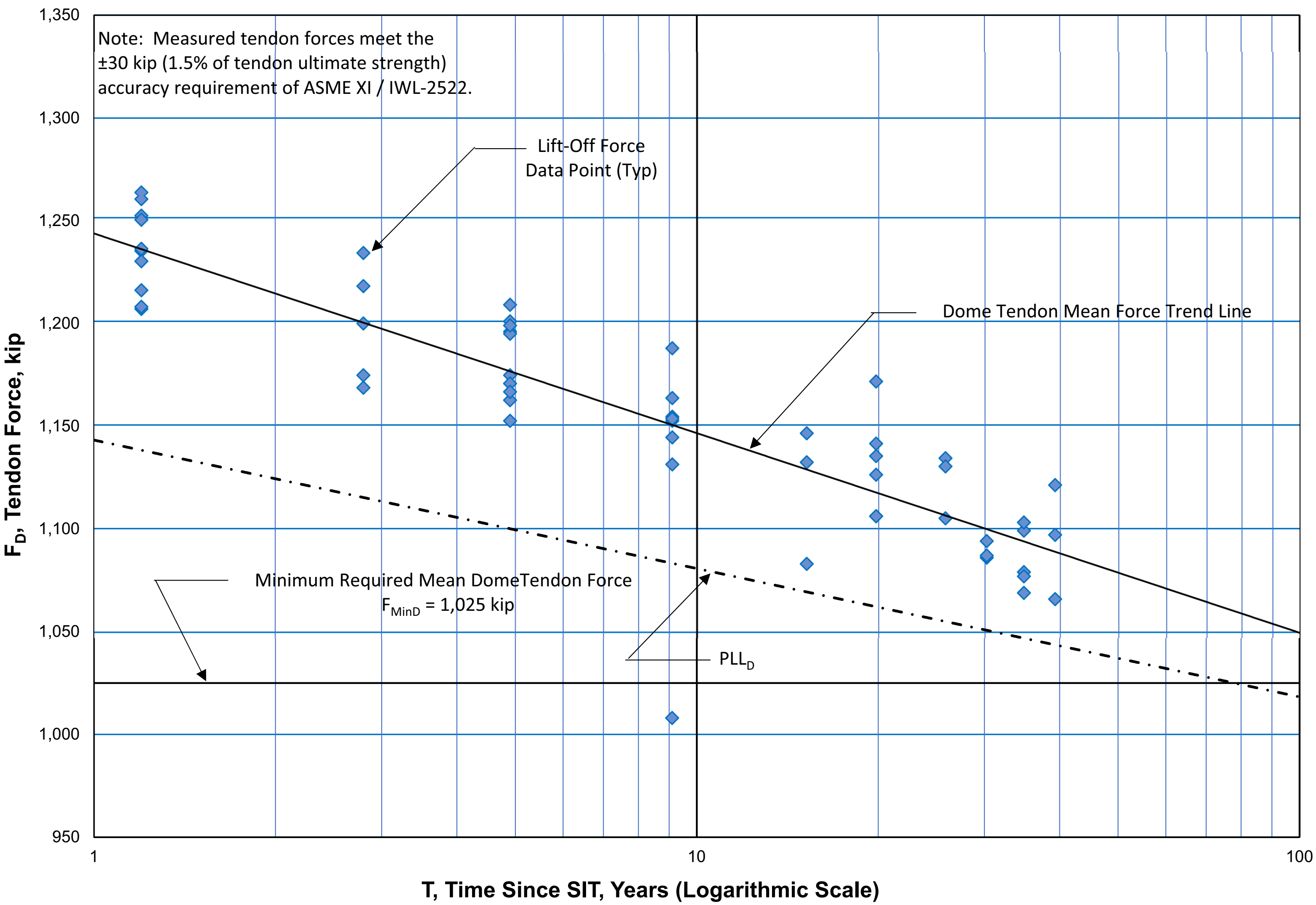

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Table 4.5-1 Containment Tendon Force Summary

Pre-Stressing Tendon Group-Mean Force and PLL Margins over MRVs at Ends of Initial (August 2042) and Subsequent (August 2062) Periods of Extended Operation					
Date / T	**Tendon Group**	**Group-Mean Force, kip**	**Margin, kip**	**Group PLL, kip**	**Margin, kip**
August 2042 / T = 61.6 Years	Hoop	1,054	54	1,020	20
	Vertical	1,256	96	1,180	20
	Dome	1,070	45	1,031	6
August 2062 / T = 81.6 Years	Hoop	1,041	41	1,011	11
	Vertical	1,244	84	1,161	1
	Dome	1,058	33	1,024	-1

4.6 CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE ANALYSIS

NOTE: Reactor Building is the site-specific term used for Containment; therefore, these terms are interchangeable.

This section includes:

- Containment Liner Plate (Section 4.6.1)
- Metal Containment (Section 4.6.2)
- Containment Penetrations Fatigue Analysis (Section 4.6.3)

4.6.1 CONTAINMENT LINER PLATE

TLAA Description:

As discussed in FSAR Section 3.8.1.1, the Reactor Building is a post-tensioned, reinforced concrete structure with an integral steel liner. The cylindrical-wall liner plate is designed to function as a leak-tight membrane, sealing the entire Reactor Building for any postulated conditions encountered throughout the operating life of the plant.

Mechanical piping penetrations are present at each location where system piping must pass through the Reactor Building wall. The part of the penetration that was procured with the containment liner is referred to as the penetration sleeve. The liner plate and the penetration sleeves meet the design requirements of the ASME B&PV Code, Section III, Class MC. This includes a fatigue waiver, which demonstrated that all six requirements of ASME Code, Section III, 1971 Edition through Winter 1972 Addenda, Subsection NB-3222.4(d), were met, providing the basis to conclude that no fatigue analysis was required for these components.

The original 40-year fatigue waiver was based upon an assumption of two startup/shutdown cycles per year, or 80 total cycles. The fatigue waiver was revised for initial license renewal to evaluate 120 startup/shutdown cycles, which also demonstrated that the six conditions in the ASME Code were met. Therefore, no fatigue analysis was required for the initial period of extended operation. Since the 60-year fatigue waiver is based upon numbers of cycles over the life of the plant, it has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

The remaining parts of the containment penetrations have separate design requirements and are described and evaluated in Section 4.6.3, Containment Penetrations Fatigue Analysis.

TLAA Evaluation:

For the subsequent period of extended operation, the fatigue waiver was revised for 80 years, based upon increasing the number of startup/shutdown cycles to 200, as shown in Table 4.6.1-1 below.

Table 4.6.1-1 Containment Liner Startup/Shutdown Cycles

Design Loads	60 Years	80 Years
Startup/Shutdown	120	200[(a)]

Footnote(s):

(a) The 80-year fatigue waiver used 200 startup and shutdown cycles, exceeding the 2 startup/shutdown cycles-per-year assumption used previously. The 80-year transient cycle projection predicts 148 startup/shutdown cycles through 80 years, based upon trending of actual transient occurrences since the beginning of plant operation (Reference 4.8-2). Therefore, the 200 cycles used in the 80-year fatigue waiver is conservative.

The revised fatigue waiver demonstrates that all six conditions in ASME Code, Section III, 1971 Edition through Winter 1972 Addenda, Subsection NB-3222.4(d) are met and therefore no fatigue analysis is required through the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The fatigue waiver for the Containment liner plate and penetration sleeves has been projected to the end of the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.6.2 METAL CONTAINMENT

Containment is provided by the Reactor Building, a reinforced concrete structure with a steel liner. Therefore, the topic of metal containment fatigue analysis is not applicable.

4.6.3 CONTAINMENT PENETRATIONS FATIGUE ANALYSIS

TLAA Description:

The Reactor Building main steam penetrations were designed in accordance with ASME Code, Section III, 1974 Edition through Winter, 1975 Addenda, as specified in FSAR Figure 3.8-15. No other Reactor Building penetrations meet TLAA criterion 6 of 10 CFR 54.3(a). The design analysis for the main steam penetrations evaluated the numbers of applicable transient cycles required by the design specification and demonstrated that the requirements of ASME Code, Section III, 1974 Edition through Winter 1975 Addenda, Subsection NC, for Class 2 components were met. Since the design analysis is based upon numbers of cycles over the life of the plant, it has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

TLAA Evaluation:

Reactor Building main steam penetrations consist of three main components. The first is the penetration sleeve, which was evaluated in Section 4.6.1, Containment Liner Plate. The remaining components include the section of process pipe passing through the penetration and the attachment assemblies both inside and outside of the containment wall that connect the process pipe to the sleeve. Even though the penetration internals are ASME B&PV Code, Class 2, the design specification required the main steam penetrations to be analyzed using the Class 1 design transients listed in Table 4.3.1-1.

The evaluation of the Reactor Building main steam penetrations compared the numbers of cycles projected to occur through 80 years of plant operation to the 40-year design transient cycles. The 40-year design transients have been demonstrated to bound the 80-year cycle projections, so the TLAA will remain valid for the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The fatigue analysis for the Reactor Building main steam penetration internals remains valid for the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

The following plant-specific safety analyses involve time-limited assumptions defined by the current operating term and are presented in this section.

- Crane Load Cycle Limits (Section 4.7.1)
- Reactor Coolant Pump Flywheel Fatigue Crack Growth Analyses (Section 4.7.2)
- Leak-Before-Break (Section 4.7.3)
- Steam Generator Tube Wear Evaluation (Section 4.7.4)

4.7.1 CRANE LOAD CYCLE LIMITS

TLAA Description:

Cranes meeting the intent of NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” (Reference 4.8-36) are within the scope of subsequent license renewal. Other cranes and hoists that are not within the scope of NUREG-0612, but used to lift irradiated fuel assemblies, are also within the scope of subsequent license renewal. Cranes within the scope of subsequent license renewal that were designed to meet the intent of Crane Manufacturers Association of America (CMAA) Specification 70 (Reference 4.8-37) and that have a defined service life as measured in load cycles are identified as TLAAs.

TLAA Evaluation:

Method of Evaluation - Scope

For the load handling systems requiring evaluation, Table 4.7.1-1 below summarizes the design specifications and service class

Table 4.7.1-1 Design Summary

Load Handling System	Design Specification(s)	Service Class
Reactor Cavity Manipulator Crane (refueling machine)	CMAA Spec 70; ANSI B30.2	A
Spent Fuel Pit Bridge Crane (fuel handling machine)	CMAA Spec 70; ANSI B30.2	A
125/15-ton Fuel Handling Building Crane (spent fuel cask handling crane)	CMAA Spec 70; ANSI B30.2	A
Reactor Building Polar Crane	CMAA Spec 70; ANSI B30.2	A
3-ton Fuel Handling Building Hoist (transfer canal gate hoist)	CMAA Spec 70	A
'B' Loop Auxiliary Crane	CMAA Spec 70; ASME B30.22	A

Methodology of Analysis - Acceptance Criteria

CMAA Specification 70-1975 (Reference 4.8-37) presents the bounding number of load cycles and allowable stress range for each service class and stress category. Similarly, CMAA Specification 70-2010 (Reference 4.8-38) presents the bounding number of load cycles based on the most limiting "mean effective load factor" for each service class. These design criteria define the acceptable service limits for the TLAA. As identified in Table 4.7.1-1, all load handling systems within the scope of this evaluation were designed to Service Class "A" (i.e., standby) service requirements. It is conservatively assumed that all lift cycles are performed near capacity with the cranes subjected to the highest "allowable stress range" for Service Class "A" cranes as described in CMAA Specification 70-1975 or having the most limiting "mean effective load factor" as described in CMAA Specification 70-2010. For these extreme conditions, the maximum allowable number of loading cycles is 100,000. Therefore, the acceptance criterion for each crane is 100,000 cycles.

Based on 18-month refuel cycles, plant operation will end in 2062 during refuel cycle 54. The total projected lifts are based on conservative estimated lifts during each refuel cycle.

Reactor Cavity Manipulator Crane (refueling machine)

The reactor cavity manipulator crane performs fuel handling operations in the Reactor Building. It also provides a monorail hoist as a means of tool support and operator access for long tools used in various service, latching and handling functions.

The reactor cavity manipulator crane lift load consists of the combination of a spent fuel or new fuel assembly and handling tool. Although the crane and hoist have capacities of 4,000 lbs. and

3,000 lbs., respectively, the refueling loads the are procedurally controlled to handle are ≤ 2,500 lbs.

Conservatively assuming 400 lifts each refueling cycle for the main hoist (i.e., a full core offload of 157 fuel assemblies, a full core reload of 157 fuel assemblies and miscellaneous fuel assembly shuffles), and 54 refueling cycles, a total of 21,600 cycles are projected through 80 years of plant operation. The same number of lifts are conservatively used for fuel handling tools. This results in a total of 43,200 projected lifts, as identified in Table 4.7.1-2 below.

Table 4.7.1-2 Reactor Cavity Manipulator Crane

Heavy Load Description	Approximate Load Weight (lbs.)	Lifts per Refuel Cycle	Refuel Cycles	Number of Lifts Over Plant Life
Fuel assembly	≤ 2,500	400	54	21,600
Fuel handling tools (such as the thimble plug handling tool, control rod drive shaft unlatching tool, and control rod drive shaft handling fixture)	≤ 2,500	400	54	21,600
80-year total estimated load lifts				43,200

Spent Fuel Pit Bridge Crane (fuel handling machine)

The spent fuel pit bridge crane is installed for the handling of new and spent fuel assemblies in the spent fuel pool, transfer canal and cask loading pit. The crane's lift load consists of the combination of a spent fuel or new fuel assembly and handling tool. Although the crane has a capacity of 2-tons, the loads are procedurally controlled to be ≤ 2,500 lbs.

Conservatively assuming 400 lifts each refueling cycle (i.e., a full core offload of 157 fuel assemblies, a full core reload of 157 fuel assemblies and miscellaneous fuel assembly shuffles), and 54 refueling cycles - results in 21,600 cycles projected to 80 years. Another 200 lifts are included for shuffling control rods and other pre-outage staging. For dry fuel storage moves, 75 lifts are conservatively assumed. This results in a total of 36,450 projected lifts, as identified in Tables 4.7.1-3.

Table 4.7.1-3 Spent Fuel Pit Bridge Crane

Heavy Load Description	Approximate Load Weight (lbs.)	Lifts per Refuel cycle	Refuel Cycles	Number of Lifts Over Plant Life
Fuel assembly	≤ 2,500	400	54	21,600
Shuffling control rods and other pre-outage staging	≤ 2,500	200	54	10,800
Dry fuel storage moves	≤ 2,500	75	54	4,050
80-year total estimated load lifts				36,450

125/15-ton Fuel Handling Building Crane (spent fuel cask handling crane)

The 125/15-ton fuel handling building crane is installed to unload and transfer new fuel assemblies, and to move, load, and unload casks during spent fuel transfer and storage operations. The crane is rated for 125 tons and designed to CMAA Specification 70. The crane is equipped with an auxiliary hoist rated for 15 tons. Lifts using both the 125-ton main hoist and the 15-ton auxiliary hoist are combined for this evaluation.

The 125/15-ton fuel handling building crane was upgraded to be capable of supporting a 125-ton load during a design seismic event. The upgrade included modifications to both the 125-ton main hoist and the 15-ton auxiliary hoist with the main hoist returned to service in January 2013 and the auxiliary hoist returned to service in August 2013.

Table 4.7.1-4 125/15-ton Fuel Handling Building Crane

Heavy Load Description	Approximate Load Weight (lbs.)	Lifts per Refuel cycle	Refuel Cycles	Number of Lifts Over Plant Life
HI-TRAC transfer cask (with MPC, spent fuel, SFP water, neutron shield water, lifting devices)[b]	249,764	2	54	108
HI-STORM overpack (empty, no lid)	188,600	2	54	108
HI-TRAC transfer cask (empty)	114,538	3	54	162
RCP motor[a]	77,140	4	54	216
Cask loading pit VECASP	50,600	2	54	108
Irradiated specimen shipping cask and vendor-supplied lift device	50,000	6	54	324
MPC-37 (empty)	37,000	3	54	162
Stack-up mating device	23,000	6	54	324
HI-STORM closure lid	22,000	6	54	324
Cask support pedestal (decon pit)	15,000	2	54	108
Miscellaneous lifts	≤ 15,000	400	54	21,600
80-year total estimated load lifts				23,544

Footnotes:

(a) All three RCP motors are changed out every 6 cycles. Therefore, there are 12 lifts in 6 cycles (or an average of 2 RCP motor lift per cycle) to account for the motor being removed and the replacement motor being installed. This number is doubled to account for unanticipated lifts. The RCP motor is moved to the Fuel Handling Building for maintenance.

(b) Based on moving 4 casks every 3 years for dry fuel storage campaigns.

Reactor Building Polar Crane

The reactor building polar crane has a 360-ton rated capacity. The reactor building polar crane is installed to handle the heavy loads listed in Table 4.7.1-5. Crane operations associated with reactor vessel (RV) assembly and disassembly are governed by task-specific procedures. Loads handled by the reactor building polar crane during a typical refueling outage are all less than half the rated capacity and thus would result in stress ranges less than half of the design stress range for 100,000 cycles. Similarly, many of the loads applied to the 25-ton hoist are appreciably lower than the rated load.

Table 4.7.1-5 Reactor Building Polar Crane

Heavy Load Description	Approximate Load Weight (lbs.)	Lifts per Refuel cycle	Refuel Cycles	Number of Lifts Over Plant Life
Integrated head assembly (includes RV head and CRDM fans)[d]	315,000	2	54	108
Lower internals and lift rig[b]	230,000	N/A	54	10
Upper internals and lift rig	120,000	2	54	108
RCP motor[a]	77,140	4	54	216
RCP casing and lift beam[c]	52,000	N/A	54	10
RCP internals[c]	48,000	N/A	54	10
Miscellaneous lifts	≤ 30,000	300	54	16,200
Large equipment placement lifts - initial construction and major equipment replacement; lifts in support of needed maintenance or inspections.	Various	500 over life	54	500
80-year total estimated load lifts				17,162

Footnote(s):

(a) All three RCP motors are changed out every six cycles. Therefore, there are 12 lifts in six cycles (or an average of two RCP motor lift per cycle) to account for the motor being removed and the replacement motor being installed. This number is doubled to account for unanticipated lifts.

(b) Actual planned lifts are once per 10-year ISI inspection interval. 10 lifts are conservatively assumed for 80 years.

(c) Actual lifts of the RCP casings or internals rarely occur during the operating life of the plant. The use of 10 lifts for plant life is conservative and covers possible change out of all three RCPs.

(d) Load weight includes reactor vessel head studs.

3-ton Fuel Handling Building Hoist (transfer canal gate hoist)

The 3-ton fuel handling building hoist is physically attached to the 125/15-ton fuel handling building crane trolley specifically for removal and replacement of the fuel transfer canal gate. Eight cycles per refuel cycle would account for pre-outage, pre-offload, pre-load, and post-reload lifts. However, 20 lifts are conservatively assumed to bound any testing or other lifts. This results in 1,080 projected lifts for 80 years of plant operation as identified in Table 4.7.1-6.

The actual load of 4,500 lbs. is 75% of the rated capacity. Therefore, the limit of 100,000 cycles is conservative for this evaluation.

Table 4.7.1-6 3-ton Fuel Handling Building Hoist

Heavy Load Description	Approximate Load Weight (lbs.)	Lifts per Refuel cycle	Refuel Cycles	Number of Lifts Over Plant Life
Canal gate and 2-part sling cable	4,500	20	54	1,080
80-year total estimated load lifts				1,080

'B' Loop Auxiliary Crane

During RF23 (Spring 2017), the current 'B' loop auxiliary crane was installed. The 'B' loop auxiliary crane is used to handle miscellaneous tools, boxes, stud racks and other commodities within the vicinity of the Reactor Building equipment hatch (i.e., between 'B' and 'C' steam generator enclosures).

The 'B' loop auxiliary crane assembly is a pedestal-mounted, hydraulic crane with telescoping boom and turret which rotates through 360-degrees. The assembly also includes a 20-ton electric hoist. The 'B' loop auxiliary crane capacity varies from 6,000 lbs. to 40,000 lbs. based on boom angle and length.

The 'B' loop auxiliary crane operation is restricted from the beginning of the integrated head assembly (IHA) lift, until all fuel is unloaded from the RV and stored in the Fuel Handling Building. From the date of installation until the end of plant life, there will be 31 refueling cycles remaining. Conservatively assuming 1,000 lifts per cycle, the projected number of lifts over the life of the plant is 31,000 as identified in Table 4.7.1-7.

Table 4.7.1-7 'B' Loop Auxiliary Crane

Heavy Load Description	Approximate Load Weight (lbs.)	Lifts per Refuel cycle	Refuel Cycles	Number of Lifts Over Plant Life
Reactor vessel stud rack, toolboxes, and power plant components	≤ 40,000	1,000	31	31,000
80-year total estimated load lifts				31,000

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

For each evaluated crane, the total number of projected load cycles is less than the maximum design allowable 100,000 cycles for Service Class “A” cranes. Therefore, the load cycle analyses remain valid for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

The total projected load cycles for the cranes identified in Table 4.7.1-8 subject to TLAA evaluation based on past and future use is summarized as follows:

Table 4.7.1-8 Evaluation Summary

Load Handling System	CMAA Service Class	Design Allowable Load Cycles	Projected Number of Load Cycles for 80 Years	Valid for 80 Years
Reactor cavity manipulator crane (refueling machine)	A	100,000	43,200	Yes
Spent fuel pit bridge crane (fuel handling machine)	A	100,000	36,450	Yes
125/15-ton fuel handling building crane (spent fuel cask handling crane)	A	100,000	23,544	Yes
Reactor building polar crane	A	100,000	17,162	Yes
3-ton fuel handling building hoist (transfer canal gate hoist)	A	100,000	1,080	Yes
'B' loop auxiliary crane	A	100,000	31,000	Yes

4.7.2 REACTOR COOLANT PUMP FLYWHEEL FATIGUE CRACK GROWTH ANALYSES

TLAA Description:

Failure of the reactor coolant pump (RCP) flywheel due to fatigue-crack growth is a potential plant-specific TLAA. The potential failure of the RCP flywheel is due to the growth of an undetected fabrication flaw, which could grow to the critical flaw size during normal or accident conditions.

Westinghouse and the Pressurizer Water Reactor (PWR) Owners Group (PWROG) have analyzed this TLAA generically for Westinghouse plants for 40 years in WCAP-14535-A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,” (Reference 4.8-16), and for 60 years in WCAP-15666-A, “Extension of Reactor Coolant Pump Motor Flywheel Examination” (Reference 4.8-17). The reactor coolant pump (RCP) flywheel is discussed in FSAR, Section 18.3.6.3, which explains that a fatigue crack growth (FCG) analysis was performed, assuming 6,000 cycles of pump starts and stops, which was shown to bound a 60-year plant life.

The RCP flywheel inspection is specified in the Technical Specification (Reference 1.7-17). Section 6.8.4, Item j. In lieu of NRC Regulatory Guide 1.14, C.4.b(1) and C.4.b(2) (Reference 4.8-18), a qualified, in-place, UT examination may be conducted at a 20-year interval over the volume from the inner bore of the flywheel to the circle at one-half of the outer radius. Alternatively, a surface examination (MT and/or PT) may be performed of the exposed surfaces of the removed flywheel. This is consistent with the evaluation in WCAP-15666-A. No recordable indications have been detected for the examinations performed on the RCP flywheel over the service life that could invalidate the existing analysis.

The RCP flywheel FCG analysis is applicable since WCAP-15666-A, is credited with supporting the current 20-year in-service inspection period and is within the current licensing basis of the plant. Since it is based upon 60-year time-limited assumptions (60-year cycle projections), and is used to support safety determinations, it has been identified as a TLAA requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

The TLAA methodology in WCAP-15666-A, for RCP flywheel FCG was re-evaluated and re-approved by the NRC in PWROG-17011-NP-A, “Update for Subsequent License Renewal: WCAP-14535-A, ‘Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination’ and WCAP-15666-A, ‘Extension of Reactor Coolant Pump Motor Flywheel Examination’" (Reference 4.8-15), which shows that the RCP motor flywheels have a very high tolerance for the presence of flaws, especially with the 1500-rpm overspeed limit. As noted in WCAP-15666-A, the probabilistic assessment evaluates all credible flywheel speeds, and PWROG-17011-NP-A uses the same probabilistic assessment methodology.

The stress and fracture evaluation performed in PWROG-17011-NP-A discussed failure modes and degradation mechanisms. Extending the operating period to 80 years of operation has no effect upon the ductile failure analysis, non-ductile failure analysis, or excessive deformation analysis since no time-limited variables were used in these evaluations. As shown in Table 4.7.2-1, below, the 6,000 cycles analyzed in the FCG analysis bound the 80-year projection of 2,000 pump start and stop cycles.

Table 4.7.2-1 RCP Start/Stop Cycle Projections for 80 Years

Numbers of Design Heatup/Cooldown Cycles[(a)]	Estimated RCP Start/Stop Cycles per Heatup/Cooldown Cycle[(b)]	Total Projected RCP Start/Stop Cycles for 80 years
200	10	2,000

Footnote(s):

(a) The 200 heatup and cooldown design cycles have been demonstrated to remain bounding for 80 years of plant operation in Table 4.3.1-1.

(b) Ten start/stop cycles per heatup/cooldown cycle (2,000 cycles) is based on operator interviews and is less than 100 start/stop cycles per year (6,000 cycles) assumed in WCAP-15666-A, demonstrating operational margin.

Therefore, the FCG analysis described in WCAP-15666-A, and PWROG-17011-NP-A remains valid for 80 years of operation. The FCG analysis shows that even with a large, assumed flaw, the crack growth for 80 years of operation is negligible.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The RCP flywheel flaw evaluation performed in PWROG-17011-NP-A demonstrates that the FCG analysis described in WCAP-15666-A, Revision 1, based upon 6,000 pump starts and stops, remains valid for the subsequent period of extended operation and is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

4.7.3 LEAK-BEFORE-BREAK

TLAA Description:

10 CFR 50, Appendix A, General Design Criterion (GDC) 4 (Reference 1.7-16), allows for the use of leak-before-break (LBB) methodology for excluding the dynamic effects of postulated ruptures in reactor coolant system piping. The fundamental premise of the LBB methodology is that the materials used in a nuclear power plant are sufficiently tough that even a large through wall crack would remain stable and would not result in a double ended pipe rupture.

As discussed in FSAR Sections 3.6, 3.9.3.1.1, and 18.3.2.2 (Reference 1.7-18), postulated breaks in the reactor coolant system (RCS) primary loop piping, except for branch line connections, have been eliminated. WCAP-13206, Revision 0, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Virgil C. Summer Nuclear Power Plant,” (Reference 4.8-11) demonstrated that postulated breaks in the reactor coolant loop piping, except for branch line connections can be excluded from the design basis. The methodology of WCAP-13206 is consistent with the original, generic work performed as the basis of Generic letter 84-04, “Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops” (Reference 4.8-21).

Over the years, subsequent LBB evaluations were performed to demonstrate that the LBB evaluations and conclusions reached in WCAP-13206 remain valid. These evaluations were documented as follows:

- Steam Generator snubber elimination and Steam Generator Replacement/Uprating programs per WCAP-13206 Revision 1, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Virgil S. Summer Nuclear Plant, Revision 1” (Reference 4.8-47).
- Hot leg loop A replacement spool piece per WCAP-13206 Revision 2, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Virgil C. Summer Nuclear Power Plant” (Reference 4.8-48).
- Mechanical stress improvement process on the Loop B and C RV outlet nozzles (RVON), and the Initial License Renewal project (60 years) per WCAP-13206 Revision 3, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Virgil C. Summer Nuclear Power Plant” (Reference 4.8-49).

Since these analyses are based upon variables associated with the life of the plant, they have been identified as TLAAs that require evaluation for the subsequent period of extended operation.

TLAA Evaluation:

To maintain the LBB design basis for the plant, the LBB evaluation was performed considering an 80-year plant life. The aging effect identified in this TLAA is thermal aging of cast austenitic stainless steel (CASS) material resulting in embrittlement, which is a decrease in the ductility, impact strength, and fracture toughness and an increase in hardness and tensile strength of the material. This TLAA considers lower bound fully aged fracture toughness properties.

The fatigue crack growth (FCG) evaluation performed in WCAP-13206, Revision 4, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Virgil C. Summer Nuclear Power Plant” (Reference 4.8-27), is a defense-in-depth evaluation to demonstrate that small surface flaws do not become through wall flaws over the life of the plant. The FCG evaluation was based on a generic model with representative design transients and cycles that bound the 40-year design transients.

WCAP-13206, Revision 4 re-evaluates all of the inputs for the above changes to ensure that the existing LBB evaluation conclusions remain applicable for the subsequent period of extended operation. Additionally, the evaluation reconciled any impacts on the LBB analysis due to the replacement RV closure head and the integrated head assembly.

The LBB analysis documents the plant specific geometry, loading, and material properties used in the fracture mechanics evaluation. Mechanical properties were determined at operating temperatures. Since the reactor coolant loop includes CASS elbows, fracture toughness values that considered thermal aging were determined for each heat of material. Lower bound fully aged fracture toughness properties were used in the LBB evaluation for the SA351-CF8A material.

The updates made in WCAP-13206, Revision 4 include recalculation of the delta ferrite and saturated (fully aged) lower bound fracture toughness properties based on NUREG/CR-4513, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems.” The most limiting fracture toughness values calculated using Revision 1 and Revision 2 of NUREG/CR-4513 (References 4.8-27 and 4.8-14, respectively) were conservatively considered in the updates to WCAP-13206, Revision 4.

FCG analysis is not a requirement for the LBB analysis since the basis of the evaluation is a postulation of a through-wall flaw, whereas FCG analysis is performed based on the surface flaw. Furthermore, the Issues Analysis in the Federal Register notice of the Final Rule to 10 CFR 50 Modification of General Design Criterion 4 Requirements Against Dynamic Effects of Postulated Pipe Ruptures, 52 FR 32626 (Reference 4.8-12) indicates, “the Commission deleted the fatigue crack growth analysis in the proposed rule. This requirement was found to be unnecessary because it was bounded by the crack stability analysis.”

Nevertheless, the FCG in WCAP-13206, Revision 4 was documented and retained to keep with historical precedent to demonstrate that small surface flaws will not result in a through-wall flaw over the design life of the plant. The aspect ratio and crack size for the postulated initial cracks were for a typical flaw shape and large enough to be detectable during inspections. The intent of the FCG in the LBB analysis was not to use initial flaw depths that are larger than the Acceptance Tables of the ASME Code, Section XI (Reference 4.8-6), IWB-3410-1, but rather to show a defense-in-depth fatigue crack growth. Various initial flaw depths were considered in the FCG analysis to demonstrate that small non-destructive evaluation (NDE) detectable flaw sizes would be acceptable for the life of the plant (i.e. will not grow to become complete through-wall).

In summary, the analysis within WCAP-13206, Revision 4 provides a fracture mechanics demonstration of RCS primary loop integrity consistent with the NRC position for exemption from consideration of dynamic effects noted in NUREG-0800, Section 3.6.3, "Leak-Before-Break-Evaluation Procedures" (Reference 4.8-13). The LBB analysis in WCAP-13206, Revision 4 justifies the elimination of RCS primary loop pipe breaks from the structural design basis for the subsequent period of extended operation as follows:

(a) Stress corrosion cracking is precluded by the use of fracture resistant materials in the piping system and controls on reactor coolant chemistry, temperature, pressure, and flow during normal operation. However, Alloy 82/182 dissimilar metal (DM) welds are present at the RV inlet nozzle (RVIN) locations, Loop 'B' and 'C' RV outlet nozzle (RVON) locations, steam generator inlet nozzle (SGIN) locations, and steam generator outlet nozzle (SGON) locations. The Alloy 82/182 welds are susceptible to primary water stress corrosion cracking (PWSCC).

    The PWSCC effects on the loop 'B' and 'C' RVON locations have been mitigated by the application of a mechanical stress improvement process (MSIP) and are considered within the LBB evaluation. The Alloy 82/182 Loop 'A' RVON has been replaced with an Inconel 152 weld which is not susceptible to PWSCC. The Alloy 82 welds at the SGIN and SGON have been mitigated by installing Alloy 152 inlays on the inside surface of the nozzle weld as a protective barrier for the Alloy 82/182 weld PWSCC effect.

    For the unmitigated Alloy 82/182 welds at the RVIN locations, the LBB evaluation has been updated for the subsequent period of extended operation to account for PWSCC effects in WCAP-13206, Revision 4. The evaluation of the Alloy 82/182 weld locations considers a conservative factor on the leakage flaw size, which increases the leakage flaw size for the required margin of 10 on the leak rate. This increase factor accounts for PWSCC morphology characteristics (e.g., surface roughness and number of turns), on the leakage rate of a given leakage flaw size. The results of the DM weld evaluations show that the presence of Alloy 82 or 82/182 is no longer a concern for PWSCC at these locations specific to the LBB conclusions in WCAP-13206, Revision 4.

    For the RVIN DM welds, the potential for PWSCC is adequately managed through volumetric inspections which meet the required frequency of examination in accordance with ASME Code Case N-770-5 "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 Section XI, Division 1" (Reference 4.8-28). The ASME Code validated that the inspection frequency required for unmitigated DM welds in the cold leg is appropriate per generic flaw tolerance evaluation as documented in MRP-349, "Material Reliability Program: PWR Reactor Coolant System Cold-Loop Dissimilar Metal Butt Weld Reexamination Interval Extension" (Reference 4.8-29).

(b) Evaluation of the reactor coolant piping considering the thermal aging effects for the subsequent period of extended operation and the use of the most limiting fracture toughness properties ensures that each material profile is appropriately bounded by the LBB results documented in WCAP-13206, Revision 4. For local and global failure mechanisms, all locations are evaluated using cast austenitic stainless steel properties (SA 351-CF8A) which present a limiting condition due to the thermal aging effects. The cast austenitic stainless steel fracture toughness properties also present a limiting condition when compared to the fracture toughness properties of the weld metals, including the Alloy 82/182, Alloy 82, or Alloy 152 dissimilar metal welds found in the RVIN, RVON, SGIN, and SGON locations.

(c) Water hammer should not occur in the RCS piping because of system design, testing, and operational considerations.

(d) The effects of low and high cycle fatigue on the integrity of the primary piping are negligible.

(e) Ample margin exists between the leak rate of small stable flaws and the capability of the reactor coolant system pressure boundary leakage detection system.

(f) Ample margin exists between the size of small stable flaws described in item (e) and the larger stable critical flaws.

(g) Ample margin exists in the material properties used to demonstrate end-of-service life (fully aged) stability of the critical flaws.

For the critical locations, flaws are identified that will be stable because of the ample margins described in e, f, and g above.

Based on the above discussions, the LBB conditions and all recommended margins are satisfied for the reactor coolant system primary loop piping. It is therefore concluded that dynamic effects of reactor coolant system primary loop piping breaks need not be considered in the structural design basis for the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The assessment performed in WCAP-13206, Revision 4 determined that the crack stability results, fracture toughness, and fatigue crack growth results are acceptable for the subsequent period of extended operation. Therefore, the LBB analysis has been projected to the end of the subsequent period of extended operation and is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

4.7.4 STEAM GENERATOR TUBE WEAR EVALUATION

TLAA Description:

A 40-year Steam Generator (SG) Flow-Induced Vibration (FIV) and Tube Wear Evaluation was performed in support of the design of the replacement SGs installed in 1994 and the 4.5% power uprate approved in 1996.

Steam generator tube wear is discussed in FSAR Section 5.5.2.3.4, and references Westinghouse Report No. WNEP-9314, “Delta 75 Steam Generator Flow Induced Vibration and Tube Wear / Corrosion Evaluation” (Reference 4.8-23) for the replacement SGs and has a time-limited aspect. Therefore, SG tube wear has been identified as a TLAA requiring evaluation for subsequent license renewal.

TLAA Evaluation:

The replacement SGs were installed 12 years after the Commercial Operation date of August 1982. The original limiting level of tube wear was calculated to be 5.8 mils for postulated bounding power uprate conditions over a 40 year time period. When considering the original 12 years of plant operation, the analysis for a 40 year time period corresponds to 52 years of plant life. To address an 80 year plant life for subsequent license renewal, another 28 years of tube wear is projected. Using a linear adjustment, the projected tube wear considering bounding power uprate conditions at the end of 80 years of plant operation is 9.9 mils. This is below the 40% through-wall wear depth of 16 mils, which is the Technical Specification depth at which tubes are plugged for tube wear.

Therefore, steam generator tube wear is projected to be acceptable for the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

Although the tube wear evaluation has been projected to the end of the period of extended operation, the effects of aging on the intended function(s) of the steam generator tubes will be adequately managed by the Steam Generators program (B2.1.10) for the subsequent period of extended operation and is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

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Virgil C. Summer Nuclear Station

Application for Subsequent License Renewal

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FSAR Supplement

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APPENDIX A

A0 INTRODUCTION

This appendix provides the information to be submitted in a Supplement to the Final Safety Analysis Report (FSAR) as required by 10 CFR 54.21(d) for the Virgil C. Summer Nuclear Station (VCSNS), Unit 1, Subsequent License Renewal Application (SLRA). Section 4.0 of the SLRA documents the evaluations of time-limited aging analyses (TLAA) for the subsequent period of extended operation. Appendix B of the SLRA provides descriptions of the programs and activities that manage the effects of aging for the subsequent period of extended operation. The information in Section 4.0 and Appendix B was used to prepare this appendix.

This appendix, which comprises the FSAR supplement, includes the following sections:

- Section A1 contains summary descriptions of the aging management programs (AMPs) used to manage the effects of aging during the subsequent period of extended operation. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 or require enhancements. Commitments for additional programs and program enhancements are identified in Section A4, Subsequent License Renewal Commitments. In addition, a discussion on quality assurance and operating experience related to aging management programs is provided in this section.
- Section A2 contains summary descriptions of AMPs used for management of TLAAs during the subsequent period of extended operation. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 or require enhancements. Commitments for additional programs and program enhancements are identified in Section A4, Subsequent License Renewal Commitments.
- Section A3 contains evaluation summaries of TLAAs for the subsequent period of extended operation.
- Section A4 contains summary descriptions of subsequent license renewal commitments.

  Table A4.0-1, Subsequent License Renewal Commitments, includes the commitments for subsequent license renewal along with an associated schedule indicating when Dominion plans to complete each commitment.

Following issuance of the subsequent renewed operating license, information currently in the License Renewal section of the FSAR, Chapter 18 will be replaced with the information in Appendix A described above. This is consistent with the requirements of 10 CFR 50.71(e). Upon inclusion in the FSAR, future changes to the information in FSAR Chapter 18 will be made under the provisions of 10 CFR 50.59.

A1 SUMMARY DESCRIPTIONS OF AGING MANAGEMENT PROGRAMS

The results of the integrated plant assessment and evaluation of time-limited aging analyses (TLAA) identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the subsequent period of extended operation. Sections A1 and A2 describe these programs and their implementation activities.

Quality Assurance for Aging Management Programs

The Quality Assurance (QA) Program is described in Topical Report DOM-QA-1, “Dominion Energy Nuclear Facility Quality Assurance Program Description,” which implements the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” The QA Program is consistent with the summary in Appendix A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)” of NUREG-2192. The QA Program provides the basis for the corrective actions, confirmation process, and administrative controls elements of aging management programs (AMPs). The scope of the existing QA Program is expanded to also include safety-related and nonsafety-related structures and components subject to AMPs.

Consideration of Operating Experience in Aging Management Programs (AMPs)

Operating experience (OE) from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the QA Program, which meets the requirements of 10 CFR 50, Appendix B, and the OE program, which meets the requirements of NUREG-0737, “Clarification of TMI Action Plan Requirements,” Item I.C.5, “Procedures for Feedback of Operating Experience to Plant Staff.”

The OE Program at Dominion interfaces with and relies on active participation in the Institute of Nuclear Power Operations (INPO) OE program, as endorsed by the NRC. In accordance with these programs, incoming OE items are screened to determine whether they may involve age-related degradation or aging management impacts. Research and development is also reviewed. 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 to those who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry OE. Plant-specific OE associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the OE Program at Dominion.

A1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is an existing condition monitoring program that manages cracking and loss of material. The program consists of periodic volumetric, surface, and/or visual examinations, and leakage tests of ASME Code, Section XI, Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, identification of signs of degradation, and establishment of corrective actions. The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is implemented in accordance with 10 CFR 50.55a and the ASME Code, Section XI. The ASME Code, Section XI, edition and addenda will be consistent with the provisions of 10 CFR 50.55a during the subsequent period of extended operation.

Additional examinations not required by the ASME Code, Section XI, but using ASME Code, Section XI, inspection techniques and acceptance criteria, are performed in accordance with identified augmented inspection activities.

A1.2 Water Chemistry

The *Water Chemistry* program is an existing preventive program that manages cracking, loss of material, reduction of heat transfer, and wall thinning of components exposed to a reactor coolant, steam, treated borated water, and 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 EPRI 3002000505, Revision 7 (April 2014), “Pressurized Water Reactor Primary Water Chemistry Guidelines,” and EPRI 3002010645, Revision 8 (September 2017), “Pressurized Water Reactor Secondary Water Chemistry Guidelines.”

A1.3 Reactor Head Closure Stud Bolting

The *Reactor Head Closure Stud Bolting* program is an existing condition monitoring program that manages cracking and loss of material for the reactor head closure stud assembly (which includes the closure studs, washers, and nuts) and for the threads in the reactor vessel flange.

The program is implemented through procedures based on the examination requirements specified in the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, and preventive measures to mitigate cracking. The program relies on preventive measures to address reactor head closure stud bolting degradation consistent with those identified in NRC Regulatory Guide 1.65, Revision 1, “Material and Inspection for Reactor Vessel Closure Studs.”

A1.4 Boric Acid Corrosion

The *Boric Acid Corrosion* program is an existing condition monitoring program that manages loss of material due to leaking borated water on structures and components (including electrical equipment/junction boxes). This program relies, in part, on the response to 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 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 Acid Inspection Program for Pressurized Water Reactors."

A1.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is an existing condition monitoring program that addresses operating experience of degradation due to primary water stress corrosion cracking (PWSCC) for components or welds constructed from Alloy 600/82/182 and exposed to pressurized water reactor (PWR) primary coolant at elevated temperatures.

The scope of the program includes the following groups of components and materials:

- Nickel alloy components and welds identified in "Materials Reliability Program: Generic Guidance for Alloy 600 Management," (MRP-126)
- 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
- 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

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is used in conjunction with the *Water Chemistry* program (A1.2). For nickel-alloy components and welds identified in EPRI MRP-126 and addressed by the regulatory requirements of 10 CFR 50.55a, examinations are conducted in accordance with 10 CFR 50.55a and EPRI MRP-126.

A1.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

The *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program is an existing condition monitoring program that manages loss of fracture toughness of ASME Class 1 piping components constructed from CASS with service conditions above 250°C (Celsius) [482°F (Fahrenheit)].

The program determines the susceptibility of CASS piping and piping components in reactor coolant pressure boundaries with regard to thermal aging embrittlement based on the casting method, molybdenum content, and ferrite percentage.

No CASS piping or piping components within the reactor coolant pressure boundary have been determined to be potentially susceptible to thermal aging embrittlement. Therefore, additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required.

A1.7 PWR Vessel Internals

The *PWR Vessel Internals* program is an existing condition monitoring program that manages change in dimensions, cracking, loss of fracture toughness, loss of material, and loss of preload for the reactor vessel internals (RVI). The aging effect of cracking includes stress corrosion cracking, primary water stress corrosion cracking, irradiation-assisted stress corrosion cracking, and cracking due to fatigue/cyclic loading. Degradation due to loss of material can be induced by wear, and loss of fracture toughness is the result of thermal aging and neutron irradiation embrittlement. Potential causes for the aging effect of changes in dimensions are void swelling or distortion, and loss of preload can result from thermal and irradiation-enhanced stress relaxation or creep.

The *PWR Vessel Internals* program relies on implementation of the inspection and evaluation guidelines in Electric Power Research Institute (EPRI) Technical Report 3002017168, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines, (MRP-227, Revision 1-A),” and EPRI Technical Report 3002010399, “Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals – 2020 Update (MRP-228, Rev. 4)” as supplemented by a gap analysis to manage the aging effects on the reactor vessel internal components. The guidelines listed in MRP-227, Revision 1-A, provide appropriate aging management guidance for the RVI components up to a 60-year operating period. The failure modes, effects, and criticality analysis from EPRI Technical Report 3002013220, “Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Designs (MRP-191, Revision 2),” provides the basis for grouping the reactor internals components into inspection categories by assessing aging effects and relevant time-dependent aging parameters.

For the 80-year operating period, aging management is based on the EPRI documents listed for the 60-year period, and a gap analysis that integrates the interim guidance from MRP 2018-022, “Transmittal of MRP-191 Screening, Ranking, and Categorization Results and Interim Guidance in Support of Subsequent License Renewal at U.S. PWR Plants,” for additional inspections not listed for RVI components in MRP-227, Revision 1-A. The components from MRP 2018-022 include clevis insert bolts and dowels, radial support key Stellite wear surface, and clevis insert Stellite wear surface. The gap analysis further integrates guidance for inspections of the control rod guide tube continuous section sheaths and C-tubes in accordance with WCAP-17451-P, Revision 2, “Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections.”

A1.8 Flow-Accelerated Corrosion

The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion, as well as wall thinning due to erosion mechanisms. Erosion monitoring is performed for the internal surfaces of metallic piping and components to manage the aging effect of wall thinning due to cavitation, flashing, liquid droplet impingement, and solid particle erosion.

The program is consistent with NRC Generic Letter 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning,” and relies on implementation of EPRI guidelines listed in NSAC-202L, Revision 4, “Recommendations for an Effective Flow Accelerated Corrosion Program.” The erosion activity implements the recommendations of EPRI 3002005530, “Recommendations for an Effective Program Against Erosive Attack.”

The program includes (a) identifying flow accelerated corrosion (FAC)-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 inspection; (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 modeling.

The program tracks and predicts occurrences of wall thinning due to FAC using CHECWORKS-SFA™ software. The CHECWORKS-SFA™ model is evaluated and updated as required to reflect any significant changes in plant-specific operating parameters such as power uprates. Wall thinning information available from the CHECWORKS-SFA™ software is one of the tools used to determine the scope and required schedule for inspections of FAC-susceptible components.

In addition to planned inspections performed for the *Flow-Accelerated Corrosion* program, opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation.

A1.9 Bolting Integrity

The *Bolting Integrity* program is an existing condition monitoring program that manages aging by performing periodic visual inspections for indications of cracking, loss of material due to general, pitting, and crevice corrosion, microbiologically influenced corrosion, wear, and loss of preload as evidenced by leakage for safety-related and nonsafety-related closure bolting on pressure-retaining components within the scope of subsequent license renewal.

The program relies on recommendations as delineated in NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants,” and EPRI report NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” with exceptions noted in NUREG-1339 for safety-related piping. The program also relies upon industry recommendations as delineated in EPRI Report 1015336, “Nuclear Maintenance Application Center: Bolted Joint Fundamentals,” and EPRI Report 1015337, “Nuclear Maintenance Application Center: Assembling Gasketed Flanged Bolted Joints.”

The program includes inspections or testing for closure bolting for which leakage is difficult to detect, including applicable submerged bolting, and for piping systems that contain air-indoor uncontrolled, compressed air and other gases including nitrogen, refrigerant, and carbon dioxide. The absence of high-strength bolting precludes the need for sampling-based volumetric examinations for high-strength bolting. The program includes preventive measures to preclude or minimize loss of preload and cracking.

The ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program includes inspections of closure bolting within the scope of ASME Code, Section XI, and supplements this *Bolting Integrity* program. The following aging management programs manage aging effects associated with safety-related and nonsafety-related structural bolting:

- *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program (A1.13)
- *ASME Section XI, Subsection IWE* program (A1.30)
- *ASME Section XI, Subsection IWF* program (A1.32)
- *Structures Monitoring* program (A1.35)
- *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (A1.36)

A1.10 Steam Generators

The *Steam Generators* program is an existing condition monitoring program that manages the aging effects of cracking, loss of material (e.g., wall thinning), and reduction of heat transfer for the steam generators. The scope of the program includes primary-side components (e.g., U-tubes, tube plugs, channel head divider plate, channel head, tubesheet, etc.), and secondary-side components that are contained within the steam generator. The program uses volumetric inspections for the tubes, and visual inspections for the other primary-side and secondary-side components. The visual inspections of primary-side components listed above are performed in accordance with the Degradation Assessment (DA) that is prepared as each steam generator is scheduled for examination.

Provisions in the *Steam Generators* program address reporting criteria, inspection scope and frequency, assessments, plugging criteria, and water chemistry monitoring to maintain consistency with established requirements. NEI 97-06, Revision 3, “Steam Generator Program Guidelines,” and associated EPRI guidelines, provide a generic industry program to implement Technical Specifications.

As stated in the steam generator DA, tubing and primary-side inspections are performed at least a minimum of every third refueling outage for each steam generator, thus satisfying the guidance for visual inspections to be performed at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections. The DA includes a review of applicable industry operating experience (OE) and plant-specific OE which has occurred since the previous DA was performed. The DA review determines the existence of any mechanism which has not been addressed that could adversely affect steam generator primary-side or secondary-side integrity, as well as the effects of any chemistry excursions or transients that could affect existing degradation mechanisms.

The *Steam Generators* program includes preventive measures to mitigate aging related to corrosion phenomena, and through foreign material exclusion as a means to inhibit tube degradation due to wear. Identification of deposits on the secondary side of the steam generators, and the subsequent removal of sludge deposits help avoid tube degradation.

The Technical Specifications require condition monitoring and operational assessments to be performed to ensure tube integrity will be maintained until the next inspection. Operational assessments are performed after steam generator inspections have been completed to verify structural and leakage integrity.

A1.11 Open-Cycle Cooling Water System

The *Open-Cycle Cooling Water System* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that manages cracking, flow blockage, loss of material, and reduction of heat transfer for piping, piping components, and heat exchangers identified in the response to Generic Letter 89-13, "Service Water Problems Affecting Safety-Related Equipment." The program is comprised of the aging management aspects of the response to GL 89-13 and includes: (a) surveillance and control to reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of safety-related heat exchangers, and (c) routine inspections and maintenance so that corrosion, erosion, cracking, 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 (OE) and provide reasonable assurance that aging effects are adequately managed.

System and component testing, visual inspections, nondestructive examination (i.e., ultrasonic testing and eddy current testing), and chemical injection are conducted to ensure that identified aging effects are managed such that system and component intended functions and integrity are maintained. Periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function are performed in accordance with the commitments in the docketed response to GL 89-13.

A1.12 Closed Treated Water Systems

The *Closed Treated Water Systems* program is an existing program that manages cracking, loss of material, and reduction of heat transfer for components exposed to a closed treated water environment.

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 so that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation. The program uses as applicable, EPRI Report 3002000590, "Closed Cooling Water Chemistry Guideline." Microbiological testing is performed as a diagnostic chemistry parameter for selected system water treatments.

A1.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is an existing condition monitoring program that manages cracking, loss of material due to corrosion and wear, and loss of preload on bolted connections for cranes and hoists within the scope of subsequent license renewal. The program includes periodic visual inspections to detect degradation of bridge, rail, and trolley structural components and bolted connections. This program relies on the guidance in NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” ASME B30.2, “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist),” and other appropriate standards in the ASME/ANSI B30 series to manage aging. These cranes must also comply with the maintenance rule requirements provided in 10 CFR 50.65.

A1.14 Compressed Air Monitoring

The *Compressed Air Monitoring* program is an existing preventive and condition monitoring program that manages loss of material. The *Compressed Air Monitoring* program includes monitoring of air moisture content and contaminants such that specified limits are maintained, and performance of opportunistic inspections of components for indications of loss of material.

This program is consistent with the response to NRC GL 88-14, “Instrument Air Supply Problems;” and INPO SOER 88-01, “Instrument Air System Failures.” The program relies on guidance and standards provided in EPRI TR-108147, “Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079,” and ANSI/ISA-S7.3-1975, “Quality Standard for Instrument Air,” for testing and monitoring air quality and moisture. The *Compressed Air Monitoring* program activities implement the moisture content and contaminant criteria of ANSI/ISA-S7.3-1975 (incorporated into ISA-S7.0.01-1996).

Program activities include air quality checks at various locations to ensure that dew point, particulates, and hydrocarbons are maintained within the specified limits. Opportunistic inspections of the internal surfaces of select compressed air system components for loss of material are performed.

A1.15 Fire Protection

The Fire Protection program is an existing condition monitoring and performance monitoring program that requires periodic visual inspections of fire barrier components, and functional testing of fire-rated doors and the carbon dioxide (CO_2) fire suppression system. The program manages:

- Loss of material for fire-rated doors, fire damper housings, steel seismic gap covers and the CO_2 fire suppression system
- Loss of material or cracking for concrete structures, including fire barrier walls, ceilings, and floors
- Loss of material, cracking/delamination, change in material properties, and separation for non-elastomer fire barrier penetration seals, fire stops, radiant energy shields, and fire wraps and coatings
- Shrinkage and loss of strength for elastomeric fire barrier penetration seals and for seismic gap elastomers

The Fire Protection program is a risk-informed, performance-based program built upon National Fire Protection Association (NFPA) 805, “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition.” Adoption of NFPA 805 in accordance with Title 10 of the Code of Federal Regulations (10 CFR) 50.48(c) serves as the method of satisfying 10 CFR 50.48(a) and General Design Criterion 3.

A1.16 Fire Water System

The *Fire Water System* program is an existing condition monitoring program that manages aging effects associated with water-based fire protection system components. This program manages loss of material and flow blockage due to fouling by conducting periodic visual inspections, tests, and flushes performed in accordance with the NFPA 25 (2011 Edition). 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 organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed, and the source is detected and corrected. Inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

A1.17 Outdoor and Large Atmospheric Metallic Storage Tanks

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is a new condition monitoring program that manages the effects of cracking and loss of material on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil with internal pressures approximating atmospheric pressure. Tanks within the scope of this program include the condensate storage tank, reactor makeup water storage tank, refueling water storage tank, and sodium hydroxide storage tank. The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components consistent with standard industry practices. For outdoor tanks, sealant or caulking used at the concrete-component interface or the tank's design configuration minimizes the amount of water and moisture penetrating the interface by preventing water from accumulating.

This program manages cracking and loss of material by conducting periodic external visual and surface examinations. Inspections of sealant or caulking are supplemented with physical manipulation. It has been demonstrated that the in-scope stainless steel tanks are not susceptible to SCC or loss of material. Therefore, inspections of the internal and external surfaces of stainless-steel tanks will be performed by the *One-Time Inspection* program (A1.20). Thickness measurements of tank bottoms detect degradation. Inspections not conducted in accordance with ASME Code, Section XI requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A1.18 Fuel Oil Chemistry

The *Fuel Oil Chemistry* program is an existing mitigative, condition monitoring and preventive program that manages loss of material of tanks, piping, and components in a fuel oil environment. The program includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of subsequent license renewal.

This program relies on a combination of surveillance and maintenance procedures. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with Technical Specifications, Fire Protection Program Surveillances, and ASTM standards such as ASTM D 0975, D 1796, D 2276, D 2709, D 6217, and D 4057.

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 fuel oil before its introduction into the storage tanks. Where internal cleaning and inspection are not physically possible, bottom thickness measurements of inaccessible tanks will be performed in lieu of cleaning and internal inspection.

A1.19 Reactor Vessel Material Surveillance

The *Reactor Vessel Material Surveillance* program is an existing condition monitoring program that manages reduction of fracture toughness of the ferritic reactor vessel (RV) beltline materials, in accordance with the edition of ASTM E 185 available and used during fabrication of the RV. The program provides sufficient material to monitor reduction of fracture toughness due to neutron irradiation embrittlement until the end of the subsequent period of extended operation, and determines any need for operating restrictions on the irradiation temperature (i.e., cold leg operating temperature), neutron spectrum, and neutron fluence.

The *Reactor Vessel Material Surveillance* program complies with ASTM E 185-73 for the design and number of required capsules, and ASTM E 185-82 for the withdrawal schedules and test methods, as incorporated by reference in 10 CFR 50, Appendix H. 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 ensure appropriate monitoring during the subsequent period of extended operation. The *Reactor Vessel Material Surveillance* program includes removal and testing of at least one capsule with a neutron fluence of between one and two times the projected peak RV neutron fluence at the end of the subsequent period of extended operation. If a capsule meeting this criterion has not been tested previously, then the program ensures that at least one capsule will be removed and tested during the subsequent period of extended operation (or earlier) to meet this criterion.

Data from the *Reactor Vessel Material Surveillance* program is used to monitor neutron irradiation embrittlement of the RV, and provided as input to the neutron embrittlement time limited aging analyses described in Section A3.2, Reactor Vessel Neutron Embrittlement Analysis.

In accordance with 10 CFR 50, Appendix H, all surveillance capsules, including those previously removed from the RV, 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, are submitted for approval by the Nuclear Regulatory Commission (NRC) prior to implementation, in accordance with the requirements of 10 CFR 50, Appendix H, Paragraph 111.B.3. Standby capsules placed in storage (e.g., removed from the RV) are maintained for possible future insertion. If one or more capsules will not be maintained in such a way as to permit future insertion, then the NRC will be notified of the change.

The *Reactor Vessel Material Surveillance* program is also used in conjunction with the *Neutron Fluence Monitoring* program (A2.2) which monitors neutron fluence for RV components and RV internal components.

A1.20 One-Time Inspection

The *One-Time Inspection* program is a new condition monitoring program that will manage cracking, long-term loss of material, loss of material, and reduction of heat transfer of components exposed to air, condensation, fuel oil, lubricating oil, raw water, steam, treated borated water, treated water, underground, or waste water environments

The program consists 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 material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

The elements of the program include: (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; (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.

Periodic inspections instead of this program are 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. Inspections not conducted in accordance with ASME Code, Section XI requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.21 Selective Leaching

The *Selective Leaching* program is a new condition monitoring program that will manage loss of material of the susceptible materials located in a potentially aggressive environment. The materials of construction for these components may include gray cast iron, ductile iron, and copper alloys (greater than 15% zinc).

One-time inspections for components exposed to closed-cycle cooling water or treated water environments will be conducted when plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for raw water, waste water, soil, and groundwater environments, and for closed-cycle cooling water or 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 will be conducted. Periodic destructive examinations of components for physical properties (i.e., degree of de-alloying, through-wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste water, soil, and groundwater environments or for closed-cycle cooling water or treated water environments when plant-specific operating experience has revealed selective leaching in these environments.

Periodic inspections of the buried ductile iron fire service piping that is lined with a cementitious coating will be conducted to detect selective leaching. The required excavations of buried ductile iron fire service piping will be performed in accordance with the *Buried and Underground Piping and Tanks* program (A1.28).

Inspections and tests will be 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 will be performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspection procedures will include requirements for items such as lighting, distance, offset, and surface conditions. When the acceptance criteria are not met such that it is determined that the affected component be replaced prior to the end of the subsequent period of extended operation, additional inspections will be performed.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.22 ASME Code Class 1 Small-Bore Piping

The *ASME Code Class 1 Small-Bore Piping* program is an existing condition monitoring program that manages cracking in ASME Code Class 1 small-bore piping that is defined as greater than or equal to one inch nominal pipe size (NPS) and less than four inches NPS. This program utilizes volumetric or destructive examinations to augment examinations performed by the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (A1.1). One-time and periodic inspections detect flaws and discontinuities that may indicate the presence of cracking for locations within the scope of the *ASME Code Class 1 Small-Bore Piping* program including full penetration (butt) and partial penetration (socket) welds.

Age-related cracking has not been experienced in Class 1 small-bore butt-welded piping. Therefore, Category A criteria is required as described in NUREG-2191, Table XI.M35-1 for performing one-time volumetric or destructive inspections of butt welds susceptible to cracking. Should evidence of cracking be revealed by a one-time inspection of butt welds, a periodic inspection consistent with Category C criteria is required for butt welds.

With exception of the reactor coolant pump (RCP) seal injection-thermal barrier (SI-TB) nozzle welds, age-related cracking has not been identified in Class 1 small-bore socket welded piping. Category A criteria is required for examination of Class 1 small bore socket weld locations that are susceptible to cracking. Should evidence of cracking be revealed by a one-time inspection of socket welds, a periodic inspection consistent with Category C criteria is required for socket welds.

Based on the unique design of the original Westinghouse factory welds used for the RCP SI-TB joint, these factory welds are addressed as a unique subset. Inspection samples will be selected consistent with NUREG-2191, Section XI.M35, Table XI.M35-1, Category C for this subset of welds due to the cracking that occurred from 1987 to 2004. If all Class 1 RCP SI-TB welds are replaced with an improved design, the cause of the cracking will be considered mitigated and inspection samples will be selected consistent with NUREG-2191, Section XI.M35, Table XI.M35-1, Category B for this subset of welds.

A1.23 External Surfaces Monitoring of Mechanical Components

The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that manages the following aging effects:

- loss of material, cracking, and reduction of heat transfer of metallic components;
- hardening or loss of strength, loss of material, and cracking or blistering of polymeric components;
- hardening or loss of strength, and loss of material of elastomeric components;
- loss of material, cracking, and loss of preload of HVAC closure bolting; and
- reduced thermal insulation resistance

Periodic visual inspections, not to exceed a refueling outage interval, of metallic, polymeric, and insulation jacketing (insulation when not jacketed) 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 inspections conducted under this program.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of copper alloy (>15% Zn) components.

A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), are periodically inspected every 10 years during the subsequent period of extended operation.

Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.

The external surfaces of components that are buried or in underground environments are inspected by the *Buried and Underground Piping and Tanks* program (A1.28). The external surfaces of outdoor tanks and indoor large volume metallic storage tanks (capacity >100,000 gallons) are inspected by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (A1.17). Loss of material due to boric acid corrosion is managed by the *Boric Acid Corrosion* program (A1.4).

A1.24 Flux Thimble Tube Inspection

The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that manages loss of material due to wear by inspecting for the thinning of flux thimble tube walls. Flux thimble tubes provide a path for the in-core neutron flux monitoring system detectors and form part of the reactor coolant system pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor pressure vessel (RPV) where flow-induced fretting causes wear at discontinuities in the path from the RPV instrument nozzle to the fuel assembly instrument guide tube. Periodic eddy current examinations are performed to confirm the integrity of the flux thimble tubes and are consistent with the recommendations of Inspection and Enforcement Bulletin 88-09 (IEB 88-09), “Thimble Tube Thinning in Westinghouse Reactors.”

A1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that manages the following aging effects:

- Cracking or blistering, hardening or loss of strength, and loss of material of polymeric components
- Flow blockage, hardening or loss of strength, and loss of material of elastomeric components
- Cracking, flow blockage, loss of material, and reduction of heat transfer of metallic components

This program consists of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, tanks, and other components. Applicable environments include closed–cycle cooling water, raw water, treated water, diesel exhaust, air, condensation, lubricating oil, and waste water.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of aluminum, copper alloy (>15% Zn) and stainless steel components. Aging effects associated with items within the scope of the *Open-Cycle Cooling Water System* program (A1.11), *Closed Treated Water Systems* program (A1.12), and *Fire Water System* program (A1.16) are not managed by this program.

The internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service and severity of operating conditions. Opportunistic inspections continue in each period, even if the minimum number of inspections has been conducted. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength augments the visual examinations conducted under this program.

Inspections not conducted in accordance with ASME Code, Section XI, requirements will be 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.

A1.26 Lubricating Oil Analysis

The *Lubricating Oil Analysis* program is an existing preventive program that ensures that loss of material and reduction of heat transfer is not occurring by maintaining the quality of the lubricating oil or hydraulic oil. The program ensures that contaminants (primarily water and particulates) are within acceptable limits. Testing activities include sampling and analysis of lubricating oil for detrimental contaminants. Oil testing that indicates the presence of water or particulates results in the initiation of corrective action that may include evaluating for inleakage.

A1.27 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

The *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program is an existing condition monitoring program that manages loss of material and degradation of the Boral® neutron-absorbing components/materials used in the spent fuel racks. This program relies on periodic inspection, testing, monitoring, and analysis of the criticality design to assure that the required 5% sub-criticality margin is maintained in the spent fuel pool. 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 the withdrawal, inspection, and testing of Boral® coupons.

A1.28 Buried and Underground Piping and Tanks

The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that manages loss of material on external surfaces of components in soil, concrete, or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses carbon steel piping and components, gray cast iron components (fittings), ductile iron piping and components, carbon steel tanks, and stainless steel and carbon steel bolting.

The program conducts periodic and opportunistic visual inspections of the buried fire service system piping and components that facilitates examinations performed by the *Selective Leaching* program (A1.21) to manage loss of material due to selective leaching for applicable materials in soil environments.

Depending on the material, preventive and mitigative techniques include external coatings, cathodic protection, and the quality of backfill. Direct visual inspection quantities for buried components are planned using procedural categorization criteria. Transitioning to a higher number of inspections than originally planned is based on the effectiveness of the preventive and mitigative actions. Also, depending on the material, inspection activities include annual surveys of cathodic protection, nondestructive evaluation of pipe or tank wall thicknesses, and visual inspections of the pipe from the exterior. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured.

Soil sampling and testing is performed during each excavation and a station-wide soil survey based on initial baseline data is also performed once each 10-year period to confirm the soil corrosiveness level near components within the scope of subsequent license renewal for the installed material types.

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the subsequent period of extended operation an increase in the sample size is conducted.

A1.29 Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is a new condition monitoring program that will manage loss of coating integrity of the in-scope components, exposed to closed-cycle cooling water, raw water, and treated water environments, that can lead to loss of base material or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris. The program will manage loss of material or cracking for cementitious coatings/linings.

Periodic visual inspections will be conducted for each coating/lining material and environment combination applied to the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the component's or downstream component's intended function(s).

For tanks, heat exchangers and piping, accessible surfaces will be inspected. Piping inspections will be sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings will be conducted in accordance with ASTM International Standards endorsed in Regulatory Guide 1.54, Revision 3, "Service Level I, II and III Protective Coatings Applied to Nuclear Power Plants," including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications will be based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters will be evaluated by a coatings specialist. Blisters are limited to a few intact small blisters that are completely surrounded by sound material and with the size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of de-bonding. Other degraded conditions will be evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed or physical testing performed, where physically possible (i.e., sufficient room to conduct testing), in conjunction with repair or replacement of the coating/lining.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.30 ASME Section XI, Subsection IWE

The *ASME Section XI, Subsection IWE* program is an existing condition monitoring program that manages cracking, loss of leak tightness, loss of material, loss of preload, and loss of sealing. This program is in accordance with ASME Section XI, Subsection IWE, consistent with 10 CFR 50.55a, "Codes and standards," with supplemental recommendations. The *ASME Section XI, Subsection IWE* program includes periodic visual, surface, and volumetric examinations, where applicable, of the metallic pressure-retaining components of the concrete Containment for signs of degradation, damage, irregularities including discernible liner plate bulges, and for coated areas, distress that might be indicative of degradation of the underlying metal shell or liner, and corrective actions. Acceptability of inaccessible areas of the 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.

The program includes supplemental one-time surface or alternative examinations to detect cracking for specific pressure-retaining components. A one-time volumetric examination of metal liner surfaces that are inaccessible from one side will be performed if triggered by plant-specific operating experience. This supplemental volumetric examination consists of a sample of one-foot square locations that include both randomly-selected and focused areas most likely to experience degradation based on operating experience and/or relevant considerations such as environment. Inspection results will be compared with prior recorded results in acceptance of components for continued service.

In conformance with 10 CFR 50.55a(g)(4)(ii), the containment inservice inspection program will be updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the ASME Code specified 12 months before the start of the inspection interval.

A1.31 ASME Section XI, Subsection IWL

The *ASME Section XI, Subsection IWL* program is an existing condition monitoring program that manages the following aging effects for Containment concrete and the unbonded post-tensioning system:

- Cracking
- Cracking; loss of bond; and loss of material (spalling, scaling)
- Cracking; loss of material
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material (spalling, scaling) and cracking
- Loss of material
- Loss of prestress

This program also includes inspection of tendon and anchorage hardware surfaces, inspection and testing of tendon corrosion protection media, and measurement of tendon force and elongation. This program consists of periodic visual inspection of concrete surfaces for reinforced concrete containments for signs of degradation, assessment of damage, and corrective actions. 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.

A1.32 ASME Section XI, Subsection IWF

The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that manages cracking, loss of material, loss of mechanical function, and loss of preload for ASME

Class 1, 2, 3, and MC piping and component supports. 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 Part 50.55a *ASME Section XI, Subsection IWF* program. This includes a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation. If a component support does not exceed the acceptance standards of IWF-3400, but is electively repaired to as-new condition, the sample will be increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

A1.33 10 CFR Part 50, Appendix J

The *10 CFR Part 50, Appendix J* program is an existing performance monitoring program that manages cracking, loss of leak tightness, loss of material, loss of preload and loss of sealing. Leakage rates through the Containment pressure boundary are monitored, including the Containment 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. Leakage rate testing is performed in accordance with the regulations and guidance provided in 10 CFR Part 50 Appendix J, Option B; NEI 94-01, Revision 2-A, “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J,” and subject to the requirements of 10 CFR Part 54.

A1.34 Masonry Walls

The *Masonry Walls* program is an existing condition monitoring program that is implemented as part of the *Structures Monitoring* program (A1.35) and manages cracking, loss of material, and loss of material (spalling and scaling) that could impact the intended function of the masonry walls.

The safety-related structures were designed with reinforced concrete walls, thereby avoiding the use of masonry walls in safety-related structures. The *Masonry Walls* program is consistent with the applicable portions of NRC Inspection and Enforcement Bulletin (IEB) 80-11, and plant-specific monitoring proposed by Information Notice 87-67, and is used to manage shrinkage, separation, gaps, loss of material and cracking of masonry walls within the scope of subsequent license renewal such that the evaluation basis is not invalidated and intended functions are maintained.

A1.35 Structures Monitoring

The *Structures Monitoring* program is an existing condition monitoring program that monitors the condition of structures and structural supports that are within the scope of subsequent license renewal to manage the following aging effects:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; and loss of material (spalling, scaling)
- Cracking; loss of material
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material
- Loss of material; cracking
- Loss of material (spalling, scaling) and cracking
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking
- Reduction or loss of isolation function

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, and other documents) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Inspections also include seismic joint fillers, elastomeric materials; and steel edge supports and steel bracings associated with masonry walls, and periodic evaluation of groundwater chemistry and opportunistic inspections for the condition of below grade concrete. Quantitative results (measurements) and qualitative information from periodic inspections are trended with photographs and surveys for the type, 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, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.”

Qualified inspectors identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program (A1.31), the *Structures Monitoring* program (A1.35), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (A1.36).

A1.36 Inspection of Water-Control Structures Associated with Nuclear Power Plants

The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program is an existing condition monitoring program, which manages the following aging effects:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of material; loss of form
- Loss of preload

This program consists of inspection and surveillance of raw water-control structures associated with emergency cooling water systems or flood protection. The program also will include steel elements and structural bolting associated with water-control structures. In general, parameters monitored are consistent with Section C.2 of Regulatory Guide 1.127, Revision 1 (March 1978), “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” and quantitative measurements will be recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. The inspections of the water-control structures within the scope of subsequent licensing renewal are conducted at a frequency not to exceed five years. Water-control structures are not exposed to aggressive water.

A1.37 Protective Coating Monitoring and Maintenance

The *Protective Coating Monitoring and Maintenance* program is an existing condition monitoring program that manages loss of coating integrity of Service Level I coatings inside the Reactor Building. The program maintains and monitors the aging of Service Level 1 coatings consistent with Regulatory Guide 1.54, Revision 3, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.” 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 the Reactor Building (e.g., steel liner, structural steel, supports, penetrations, and concrete walls and floors) will serve to prevent or minimize the loss of material of carbon steel components due to corrosion and aids in decontamination. This program ensures that the Service Level I coatings maintain adhesion so as to not affect the intended function of the emergency core cooling systems suction strainers.

The program also provides controls over the quantity of unqualified coatings. Unqualified coating may fail in a way to affect the intended function of the emergency core cooling systems suction strainers. Therefore, the quantity of degraded and unqualified coating is controlled and assessed periodically to ensure that the amount of unqualified coating in the Reactor Building is kept within acceptable design limits to support the post-accident operability of the emergency core cooling systems.

A1.38 Electrical Insulation For Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance of the accessible electrical cable and connection electrical insulation material subject to an adverse localized environment.

Accessible in-scope electrical cable and connection insulation material is visually inspected for cable and connection insulation surface anomalies indicating signs of reduced electrical insulation resistance. If visual inspections identify degraded or damaged conditions, then testing is performed for evaluation.

Should testing be deemed necessary, a sample of each cable and connection insulation material type found within the adverse localized environment will be tested. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation material. The electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in the procedures.

A1.39 Electrical Insulation For Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program is an existing performance monitoring program that manages the aging effects of reduced electrical insulation resistance of the electrical cables and connections (cable system) electrical insulation material used in circuits with sensitive, high-voltage, low-level current signals that are subjected to adverse localized environments caused by temperature, radiation, or moisture.

The program applies to non-EQ Containment high range area radiation monitors, steam line high range gamma monitors, atmospheric radiation monitors, and neutron flux monitoring instrumentation circuits that are sensitive to reduction in conductor electrical insulation resistance.

The evaluations and testing of the electrical insulation material are completed prior to the subsequent period of extended operation and at least once every 10 years thereafter.

A1.40 Electrical Insulation For Inaccessible Medium-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance or degraded dielectric strength of non-EQ inaccessible medium-voltage power cables exposed to significant moisture.

The program applies to inaccessible or underground (e.g., installed in buried conduits, embedded raceway, duct banks, underground vaults, manholes, cable trenches, or direct buried installations) non-EQ medium-voltage power (operating voltage of 2kV to 35kV) cables within the scope of subsequent license renewal exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function.

Periodic actions are taken to prevent non-EQ inaccessible medium-voltage power cables from being exposed to significant moisture. Accessible cable conduit endpoints and manholes associated with in-scope non-EQ inaccessible medium-voltage power cables included in this program (i.e., installed in duct banks and manholes) are inspected for water accumulation, and the water is drained, as necessary.

A1.41 Electrical Insulation For Inaccessible Instrument And Control Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements

The *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the aging effect of reduced electrical insulation resistance or degraded dielectric strength of non-EQ inaccessible and underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) instrument and control cables exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function.

Periodic actions are taken to prevent non-EQ inaccessible and underground instrument and control cables from being exposed to significant moisture. Accessible manholes/vaults associated with the cables included in this program are inspected for water accumulation and the water is drained, as necessary. The inspections are performed based on actual plant-specific operating experience over time with the inspection frequency being at least once per year and after event-driven occurrences such as heavy rain, rapid thawing of ice and snow, or flooding.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.42 Electrical Insulation For Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the aging effect of reduced electrical insulation resistance or degraded dielectric strength of non-EQ inaccessible and underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried) low-voltage power (operating voltage less than 2kV) cables within the scope of subsequent license renewal exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function.

Periodic actions are taken to prevent non-EQ inaccessible and underground low-voltage power cables from being exposed to significant moisture. Accessible manholes/vaults associated with the cables included in this program are inspected for water accumulation and the water is drained, as necessary. The inspections are performed based on actual plant-specific operating experience over time with the inspection frequency being at least once per year and after event-driven occurrences such as heavy rain, rapid thawing of ice and snow, or flooding.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.43 Fuse Holders

The *Fuse Holders* program is a new condition monitoring program that will manage increased electrical resistance of connection of the metallic clamps and reduced electrical insulation resistance of the fuse holder electrical insulation material.

This program applies to fuse holders within the scope of subsequent license renewal located outside of active equipment that require aging management.

Visual inspection and testing will be utilized to identify age related degradation for both fuse holder metallic clamps and fuse holder electrical insulation material.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.44 Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements

The *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the aging effect of increased electrical resistance of the electrical cable connections (metallic parts).

This program will perform a one-time test, on a representative sample of electrical connections, to confirm the absence of loosening of connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion and oxidation. The following factors will be considered for sampling: voltage level (medium and low-voltage), circuit loading (high loading), connection type (crimped, bolted, and tap box), and location (high temperature, high humidity, vibration, etc.). Depending on the findings of the one-time test, subsequent testing may have to be performed within ten years of the initial testing.

Non-EQ electrical cable connections (metallic parts) associated with cables within the scope of subsequent license renewal will be tested prior to the subsequent period of extended operation. The specific type of test to be performed will be determined based on the type of connection and will be a proven test for detecting increased resistance of the connection.

A representative connector sample size will consist of 20% of a connector type population with a maximum sample of 25. Otherwise a technical justification of the methodology and sample size used for selecting components under test will be included as part of the program's documentation.

As an alternative to testing accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of electrical insulation materials may be implemented. When this alternative visual inspection is used to check cable connections, the inspection will be completed prior to the subsequent period of extended operation, and repeated at least every five years, thereafter. The basis for performing only the alternative visual inspection to monitor age-related degradation of cable connections will be documented.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.45 High-Voltage Insulators

The *High-Voltage Insulators* program is a new condition monitoring program that will manage loss of material and reduced electrical insulation resistance for insulators credited for recovery of offsite power that are susceptible to airborne contaminants including dust, salt, fog, cooling tower plume, or industrial effluent. This program applies to porcelain insulators.

A2 Summary Descriptions of Time-Limited Aging Analysis Aging Management Programs

A2.1 Fatigue Monitoring

The *Fatigue Monitoring* program is an existing program that manages fatigue of the mechanical or structural components with a fatigue time-limited aging analysis (TLAA) or other analysis that depends on the number of occurrences and severity of transient cycles. This program is used to monitor fatigue or other types of cyclical loading TLAAs in accordance with the acceptance criterion in 10 CFR 54.21(c)(1)(iii).

The aging management program monitors and tracks the number of occurrences and severity of design basis transients assessed in the applicable fatigue or cyclical loading analyses for the ASME Code, Class 1 vessels; ASME Code, Section III fatigue waiver analyses; and various ASME Code, Section XI, Non-Mandatory Appendix A and Appendix L evaluations used to validate time between inspections for environmentally-assisted fatigue analyses (CUF_{en} analyses) of sentinel locations in Class 1 components and piping.

The program manages cumulative fatigue damage induced by cyclic loading in the ASME Code, Class 1 vessels by monitoring and tracking the number of occurrences and severity of the design basis transients. The program also sets applicable acceptance criteria (limits) on these parameters. Parameters associated with operation of the pressurizer and pressurizer surge line during drawing and collapse of a bubble in the pressurizer (i.e., temperatures and pressures) are also monitored. Therefore, the program has two aspects; one to verify the continued acceptability of existing analyses through cycle counting or parameter monitoring and the other to provide periodically updated evaluations of the analyses to demonstrate that they continue to meet the appropriate limits.

The requirements specified in Technical Specification (TS) Section 5.7, “Component Cyclic or Transient Limit,” are applicable to the scope of this program. The program monitors the transient cycles against the transient limits specified in Technical Specification 5.7 and FSAR Table 5.2-2.

This program also implements appropriate corrective actions (e.g., reanalysis, component or structure inspections, or component or structure repair or replacement activities) when acceptance limits are approached.

A2.2 Neutron Fluence Monitoring

The *Neutron Fluence Monitoring* program is an existing condition monitoring program that manages loss of fracture toughness due to neutron fluence of the reactor pressure vessel (RPV) regions for which neutron fluence is projected to exceed 1×10^{17} n/cm^2 (E > 1 MeV) during the subsequent period of extended operation to ensure that applicable reactor pressure vessel neutron irradiation embrittlement analysis will remain within their applicable limits.

This program has two aspects: one to verify the continued acceptability of existing analyses through neutron fluence monitoring and the other to provide periodically updated evaluations of the analyses involving neutron fluence inputs to demonstrate that they continue to meet the appropriate limits defined in the current licensing basis (CLB).

Monitoring is performed 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 RPV, the monitoring methods are performed in a manner that is consistent with the monitoring methodology guidelines in Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” Neutron fluence monitoring methods that are applied to RPV locations outside of the beltline region of the RPV were justified and are consistent with NRC-approved methodology.

Results are compared to neutron fluence parameter inputs used in neutron embrittlement analyses for RPV components. This includes but is not limited to the neutron fluence inputs for the RPV upper-shelf energy analyses and equivalent margin analyses, pressure-temperature analyses, and cold overpressure protection analyses that are required to be performed in accordance in 10 CFR Part 50, Appendix G requirements, and safety analyses that are performed to demonstrate adequate protection of the RPV against the consequences of pressurized thermal shock (PTS) events, as required by 10 CFR 50.61 and applicable to the CLB. Comparisons to the neutron fluence inputs for other analyses (as applicable to the CLB) include those for reference nil-ductility transition temperature (RT_{NDT}).

Ex-vessel neutron dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the Reactor Vessel Material Surveillance program provide inputs to and have impacts on the neutron fluence monitoring results tracked by this program. In addition, regulatory requirements in the Technical Specifications or in specific regulations of 10 CFR Part 50 apply, including those in 10 CFR Part 50, Appendix G; 10 CFR 50.55a; and the PTS requirements in 10 CFR 50.61 as applicable for the CLB.

A2.3 Environmental Qualification of Electric Equipment

The *Environmental Qualification of Electric Equipment* program manages equipment thermal, radiation, and cyclical aging through the use of aging evaluations based on qualification methods given in 10 CFR 50.49. This program implements the EQ requirements in EQ Rule 10 CFR 50.49. The EQ Rule specifically requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh environments will perform applicable safety functions in those harsh environments after the effects of in-service aging. 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, environmentally qualified equipment not qualified for the current license term is refurbished or replaced, or has its qualified life extended through reanalysis or ongoing qualification prior to reaching the designated life aging limits established in the evaluation. Aging evaluations for environmentally qualified equipment that specify a qualified life of at least 40 to 60 years are time-limited aging analyses (TLAAs) for subsequent license renewal.

The *Environmental Qualification of Electric Equipment* program is consistent with the guidance of 10 CFR 50.49; NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment”; IEEE Standard 323-1971 “General Guide for Qualifying Class 1E Electrical Equipment for Nuclear Power Generating Stations”; and IEEE Standard 323-1974, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.”

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 the 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 primary 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 can be used to extend the environmental qualification of the equipment. If the qualification cannot be extended by reanalysis, the equipment is refurbished, replaced, or requalified prior to exceeding the current qualified life.

When the reanalysis assessed margins, conservatisms, or assumptions do not support reanalysis (e.g.: extending qualified life) of environmentally qualified equipment, 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 equipment environmental qualification is maintained for the subsequent period of extended operation. Ongoing qualification of electric equipment within the scope of the EQ program involves the inspection, observation, measurement, or trending of one or more indicators, which can be correlated to the condition or functional performance of the environmentally qualified equipment.

Accessible passive EQ electrical equipment within the scope of subsequent license renewal will be inspected at least once every 10 years to identify EQ electrical equipment subjected to an adverse localized environment with the first inspection performed prior to the subsequent period of extended operation.

A2.4 Concrete Containment Unbonded Tendon Prestress

The *Concrete Containment Unbonded Tendon Prestress* program is an existing condition monitoring program that manages loss of prestress of the Reactor Building tendons. This program is based on ASME Code, Section XI, Subsection IWL criteria, as supplemented by the requirements of 10 CFR 50.55a(b)(2)(viii).

The program monitors and assesses the adequacy of the prestressing force for each tendon group based on type (i.e., hoop, vertical, and dome) and other considerations (e.g., geometric dimensions, whether affected by repair/replacement, etc.). The program ensures, during each examination, that the trend lines of the measured prestressing forces remain above the minimum required value before the next scheduled examinations. Otherwise, corrective actions are taken to ensure Containment prestress adequacy. Acceptance criteria follow 10 CFR 50.55a, and ASME Code, Section XI, Subsection IWL and include construction of trend lines consistent with NRC Information Notice 99-10 (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,” provides guidance for calculating prestressing losses and predicted forces. The program incorporates plant-specific and industry operating experience.

A3 EVALUATION SUMMARIES OF TIME-LIMITED AGING ANALYSES

As part of the application for a renewed license, 10 CFR 54.21(c) requires that an evaluation of Time-Limited Aging Analyses (TLAAs) for the subsequent period of extended operation be provided. The following TLAAs, as defined in 10 CFR 54.3, have been identified and evaluated to meet this requirement.

A3.1 Identification of Time-Limited Aging Analyses

The following TLAAs have been identified and evaluated to meet 10 CFR 54.21(c) requirements. Summaries of the TLAAs applicable to the subsequent period of extended operation are included in the following sections:

- Reactor Vessel Neutron Embrittlement Analysis (Section A3.2)
- Metal Fatigue (Section A3.3)
- Environmental Qualification of Electric Equipment (Section A3.4)
- Concrete Containment Tendon Prestress Analysis (Section A3.5)
- Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis (Section A3.6)
- Other Plant-Specific Time-Limited Aging Analyses (Section A3.7)

10 CFR 54.21(c)(2) requires that the application for a renewed license include a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based upon TLAAs as defined in 10 CFR 54.3. It also requires an evaluation that justifies the continuation of these exemptions for the subsequent period of extended operation. There were no exemptions to 10 CFR 50.12 identified that are currently in effect that are based upon or are associated with a TLAA.

A3.2 Reactor Vessel Neutron Embrittlement Analysis

10 CFR 50.60 requires that all light water reactors meet the fracture toughness, Pressure - Temperature (P-T) limits, and materials surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H. The *Reactor Vessel Material Surveillance* program is described in Section A1.19. The ferritic materials of the reactor pressure vessel (RPV) are subject to embrittlement due to high energy (E > 1.0 MeV) neutron exposure. Embrittlement means the material has lower toughness (i.e., will absorb less strain energy during a crack or rupture), thus allowing a crack to propagate more easily under thermal and pressure loading. Neutron embrittlement analyses are used to account for the reduction in fracture toughness associated with the cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant). Since these neutron

embrittlement analyses are calculated based on plant life, they are identified as TLAAs. The following RPV neutron embrittlement TLAAs have been identified and evaluated to meet 10 CFR 54.21(c) requirements:

- Neutron Fluence Projections (Section A3.2.1)
- Upper-Shelf Energy (Section A3.2.2)
- Pressurized Thermal Shock (Section A3.2.3)
- Adjusted Reference Temperature (Section A3.2.4)
- Pressure-Temperature Limits (Section A3.2.5)
- Low Temperature Overpressure Protection (Section A3.2.6)

A3.2.1 Neutron Fluence Projections

Updated neutron fluence evaluations were performed and documented in WCAP-18709-NP, "V.C. Summer Nuclear Station Unit 1 Subsequent License Renewal: Reactor Pressure Vessel Extended Beltline Neutron Exposure Evaluation." RV beltline and extended beltline fast neutron fluences (E > 1.0 MeV) at the end of 80 years of operation were calculated. The analyses methodologies used to calculate fluences satisfy the guidance set forth in Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." These methodologies have been approved by the NRC and are described in detail in WCAP-18124-NP-A, "Fluence Determination with RAPTOR-M3G and FERRET," and are documented in FSAR Section 5.4.3.6, "Irradiation Surveillance Programs."

The fluence analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii). As necessary, the fluence projections were used in evaluating TLAAs.

A3.2.2 Upper-Shelf Energy

Appendix G of 10 CFR 50, Paragraph IV.A.1.a, states that reactor vessel (RV) beltline materials must have Charpy upper-shelf energy (USE) of no less than 75 ft-lb initially, and must maintain Charpy USE throughout the life of the vessel of no less than 50 ft-lb unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code, "Fracture Toughness Criteria for Protections Against Failure." The material outside the beltline was originally qualified using the requirements of the ASME Code, Section III in effect at the time of the design and fabrication of the RV. The USE analyses for the ferritic steel components (i.e., RV shell plates or forgings, nozzle plates or forgings, and associated pressure retaining welds) in the beltline region of the RV have been updated based on component neutron fluence values that have been projected to the end of the subsequent period of extended operation and the current RV surveillance test data for the facility. As documented in

WCAP 18728-NP, "V.C. Summer Nuclear Station Unit 1 Subsequent License Renewal: Evaluation of Reactor Vessel Time-Limited Aging Analyses," the materials that exceeded the 1.0×10^{17} n/cm^2 (E > 1.0 MeV) threshold at 72 EFPY are evaluated to determine their impact on USE during the subsequent period of extended operation. The projected USE values for the beltline and extended beltline materials were calculated and determined to remain above the USE screening criterion of 50-ft-lb at the end of the subsequent period of extended operation, with the limiting USE value being at 63 ft-lb.

The USE TLAA has been projected to the end of the subsequent period of extended operation and is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.2.3 Pressurized Thermal Shock

10 CFR 50.61(b)(1) provides rules for protection against pressurized thermal shock (PTS) events for pressurized water reactors and requires the reference temperature RT_{PTS} for RV beltline materials to be less than the PTS screening criteria at the expiration date of the operating license unless otherwise approved by the NRC. 10 CFR 50.61(c) provides two methods for determining RT_{PTS}, described in Regulatory Guide 1.99, Revision 2. Per WCAP-18728-NP, values were calculated performing both methods. The limiting RT_{PTS} value is 152ºF for base metal and longitudinal welds and 42.5°F for circumferentially oriented welds. The beltline and extended beltline materials in the RV are below the RT_{PTS} screening criteria values of 270°F for base metal and/or longitudinal welds, and 300°F for circumferentially oriented welds for the subsequent period of extended operation.

The PTS analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.2.4 Adjusted Reference Temperature

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline Pressure-Temperature (P-T) limit curves to account for irradiation effects. 10 CFR 50, Appendix G, defines the fracture toughness requirements for the life of the vessel. Regulatory Guide 1.99 provides the methodology for determining the ART of the limiting material. RT_{NDT} was evaluated in accordance with PWROG-21037-NP, "Determination of Unirradiated RT_{NDT} and Upper-Shelf Energy Values of the V.C. Summer Unit 1 Reactor Vessel Materials," which includes the generally accepted techniques outlined in ASME Code, Section III, Paragraph NB 2331, "Material for Vessel," and Branch Technical Position 5-3, "Fracture Toughness Requirements." The P-T limit curves for normal heatup and cooldown of the primary reactor coolant system were previously developed in WCAP-16305-NP, Revision 0, "V.C: Summer Heatup and Cooldown Curves for Normal Operation," and validated in WCAP-18729-NP, "V.C. Summer Nuclear Station Unit 1 Subsequent License Renewal: Heatup and Cooldown Limit Curves for Normal Operation."

The ART analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.2.5 Pressure-Temperature Limits

10 CFR 50, Appendix G requires that the RV be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the RV is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RV fluence.

According to NUREG-2192, Section 4.2.2.1.4, the P-T limits for the subsequent period of extended operation need not be submitted as part of the subsequent period of extended application since the P-T limits are required to be updated through the 10 CFR 50.90, “Application for Amendment of License, Construction Permit, or Early Site Permit,” licensing process when necessary for P-T limits that are located in Technical Specifications.

The current licensing basis will ensure that the P-T limits for the subsequent period of extended operation will be updated prior to exceeding the EFPY for which they remain valid. The P-T limit curves for normal heatup and cooldown of the primary reactor coolant system were previously developed in WCAP-16305-NP, “V.C. Summer Heatup and Cooldown Limit Curves for Normal Operation.” WCAP-18729-NP, “V.C. Summer Nuclear Station Unit 1 Subsequent License Renewal: Heatup and Cooldown Limit Curves for Normal Operation,” extends the applicability of the current P-T limit curves for the subsequent period of extended operation, because the current Technical Specifications P-T limit curves bound the new P-T limit curves.

The end of the subsequent period of extended operation ART values at the 1/4T and 3/4T locations remain bounded by the ART values used in the current P-T limit curves. Thus, the P-T limit curves implemented in the Technical Specifications remain valid for the subsequent period of extended operation (72 EFPY) for the cylindrical shell materials.

Since the P-T limits will be updated through the 10 CFR 50.90 process at a later, appropriate date, the effects of aging on the intended function(s) of the RV will be adequately managed for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A3.2.6 Low Temperature Overpressure Protection

The low temperature overpressure protection (LTOP) system is known at VCSNS as the Cold Overpressure Protection System (COPS). The LTOP system is required by Technical Specification Limited Condition for Operation 3.4.9.3. Per FSAR Section 5.2.2.5.2, the autoclosure interlock has been removed from the Residual Heat Removal (RHR) suction isolation valves. Therefore, the RHR system will not be isolated from the RCS due to high pressure conditions, thus making RHR relief valves a suitable option to provide LTOP. Two RHR suction relief valves provide the automatic relief capability during design basis mass injection and design basis heat injection transients to automatically prevent the reactor coolant system pressure from exceeding the pressure temperature limit curves based on 10 CFR 50, Appendix G.

The LTOPS Enabling temperature was calculated using methods of ASME Code Case N-641 to be 200°F. In accordance with the methodology in WCAP-14040-A, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,” an uncertainty of 26°F was applied. The Technical Specifications LCO 3.4.9.3 specifies an LTOP enabling temperature of 300°F, which remains conservative and can be maintained for the subsequent period of extended operation.

The LTOP system capabilities and enabling temperature remain valid for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.3 Metal Fatigue

Fatigue analyses are required on components designed to ASME Code, Section III. NUREG-2192 (Reference 1.7-5) also provides examples of components likely to have fatigue TLAAs within the CLB that would require evaluation for the subsequent period of extended operation. Searches were performed to identify these and any other potential fatigue TLAAs within the CLB. Each potential fatigue TLAA was evaluated against the definition in 10 CFR 54.3(a) to determine whether the six criteria were met for the subsequent period of extended operation. Those that were identified as fatigue TLAAs are described and evaluated in the following sections:

- Transient Cycle Projections for 80 years (Section A3.3.1)
- ASME Code, Section III, Class I Fatigue Analyses (Section A3.3.2)
- Non-Class 1 Allowable Stress Analyses (Section A3.3.3)
- Environmentally-Assisted Fatigue (Section A3.3.4)
- High-Energy Line-Break Analyses (Section A3.3.5)

A3.3.1 Transient Cycle Projections for 80 years

Fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients. FSAR Table 5.2-2 lists design transients and associated design cycles. The intent of the design basis transient definitions is to bound a wide range of possible events with varying ranges of severity in temperature and pressure. The existing fatigue analyses are based upon the original number of design cycles (40 years) and were postulated to bound 60 years of service life in support of initial license renewal. Since the fatigue analyses are based upon 40-year design cycles, these analyses are considered TLAAs that require evaluation for the subsequent period of extended operation.

A review of *Fatigue Monitoring* program (Section A2.1) data was performed to identify the number of cumulative cycles for each transient type that occurred through December 31, 2019. Baseline cycle counts were projected through an 80-year operating life, based on the actual accumulation history over the life of the plant. They do not represent a revision of the design basis. These transient cycle projections are shown in WCAP-18772-NP, “Resolution of Virgil C. Summer Nuclear Station Time-Limited Aging Analyses for Subsequent License Renewal.” A linear-rate cycle extrapolation of the total operating period was used to project the number of future occurrences beginning December 31, 2019 and ending August 5, 2062, the end of 80 years of operation.

As shown in WCAP-18772-NP, the projected cycles for 80 years of plant operation were less than the 40-year design cycles. In order to ensure the design cycles used in the Class 1 fatigue analyses remain bounding, the *Fatigue Monitoring* program (Section A2.1) will track cycles for fatigue transients listed in FSAR Table 5.2-2 and ensure corrective action is taken prior to exceeding fatigue design cycle limits.

A3.3.2 ASME Code, Section III, Class I Fatigue Analyses

Fatigue analyses were performed in accordance with ASME Code, Section III, Subsection NB requirements. Each analysis was required to demonstrate that the cumulative usage factor (CUF) for the component will not exceed the ASME Code, Section III design limit of 1.0 when the component is exposed to the 40-year design transients. In addition, a detailed fatigue evaluation is not required if components conform to the waiver of fatigue requirements per ASME Code, Section III. These fatigue waivers depend on the numbers of anticipated transients over the life of the plant and therefore constitute TLAAs.

The following Safety Class 1 components have fatigue analyses or fatigue waivers that have been evaluated for the subsequent period of extended operation:

- Control Rod Drive Mechanism
- Pressurizer
- Reactor Coolant Pumps
- Reactor Vessel and Replacement Reactor Vessel Closure Head
- Steam Generators
- ASME Code, Section III, Class 1 Component Fatigue Waivers
- ASME Code, Section III, Class 1 Piping Fatigue Analyses
- Pressurizer Surge Line

The 40-year design transients are projected to bound the 80-year projected transients. Therefore, the Class 1 fatigue analyses and fatigue waivers will remain valid for the subsequent period of extended operation.

The TLAAs associated with the Class 1 Piping and Pressurizer Surge Line are dispositioned in accordance with 10 CFR 54.21 (c)(1)(i).

In order to ensure the design cycles remain bounding for the Class 1 component fatigue analyses and fatigue waivers, the *Fatigue Monitoring* program (Section A2.1) tracks cycles for significant fatigue transients listed in Technical Specification Table 5.7-1 and FSAR Table 5.2-2. This ensures corrective action is taken prior to potentially exceeding fatigue design limits.

The effects of fatigue on the intended function(s) of ASME Code, Section III Class 1 components and fatigue waivers will be adequately managed by the *Fatigue Monitoring* program for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A3.3.3 Non-Class 1 Allowable Stress Analyses

Nuclear piping and components, designated Safety Class 2a, 2b, or 3 on station drawings, are constructed in accordance with the ASME Code, Section III, "Nuclear Power Plant Components," 1974 Edition and Addenda, Subsections NC and ND.

Non-nuclear (Balance of Plant) piping is constructed to ANSI B31.1, "Power Piping," 1967 issue with addenda through 1972.

For Non-Class 1 piping systems constructed in accordance with the above cited codes, explicit analyses of cumulative fatigue usage are not required. Instead, cyclic loading is considered in a simplified manner in the design process. Allowable thermal stresses are reduced using a stress range reduction factor based on the number of anticipated thermal cycles expected during the component operating lifetime. Stress range reduction factors are specified in ASME Code, Section III (1974 Edition and Addenda), Table NC/ND-3611.2(e)-1 and ANSI B31.1 (1967 Edition through 1972 Addenda), Table 102.3.2(c). No reduction of allowable stresses is required for piping that is subjected to less than 7,000 equivalent full temperature cycles during plant service. The evaluations for required stress reduction factors are implicit fatigue analyses because they are based on the number of fatigue cycles anticipated for the life of the component. Therefore, they are TLAAs requiring evaluation for the subsequent period of extended operation.

Non-Class 1 ASME Code Section III and ANSI B31.1 piping systems are generally subject to continuous steady state operation, and operating temperatures vary only during plant heatup and cooldown, during plant transients, or during periodic testing. Portions of Non-Class 1 piping systems that are attached to the reactor coolant system or other power cycle related systems are subject to a similar number or fewer cycles as the reactor coolant system. These include extraction steam, feedwater, gland sealing steam, main steam dump, main steam, reactor coolant, residual heat removal, and safety injection systems.

Portions of some of these systems are normally isolated from the normal power cycle and would experience fewer cycles than those portions at the system boundary. The expected number of transients for these systems is much less than 7,000 cycles for 80 years of plant operation.

Portions of various Non-Class 1 systems, designed in accordance with ASME Code Section III or ANSI B31.1 requirements, are affected by thermal and pressure transients that are different than the reactor coolant and power cycles discussed above. The affected Non-Class 1 systems include the auxiliary boiler steam and feedwater, steam generator blowdown, boron recycle, chemical and volume control, chemical volume and control vents and drains, diesel generator services, emergency feedwater, nuclear sampling, liquid waste processing, and turbine cycle sampling systems.

The basis for cycle projections have been reviewed for these systems to validate that the projected cycles for 80 years of operation remain less than 7,000 cycles. The number of cycles for each of these piping systems is projected to be less than 7,000 for 80 years of plant operation.

The Non-Class 1 allowable stress analyses remain valid for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.3.4 Environmentally-Assisted Fatigue

In support of initial license renewal, environmentally-assisted fatigue (EAF) analyses were prepared for limiting locations within the Class 1 piping systems and for ASME Code, Section III, Class 1 components that contact reactor coolant. These EAF analyses were developed to account for environmental effects on these systems and components for the initial period of extended operation. Since these analyses were based on transient cycles for the initial license renewal period, they have been identified as TLAAs that require evaluation for the subsequent period of extended operation.

For subsequent license renewal, EAF was evaluated using the methodology outlined in Section X.M1 of NUREG-2191 and Section 4.3 of NUREG-2192. The effects of the reactor water environment on CUF were examined for a set of sample critical components for the plant, including the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary that were identified through an EAF screening evaluation. The EAF screening process evaluates existing fatigue usage values for the ASME Code, Section III components and piping, including the NUREG/CR-6260 locations, to determine the sentinel locations for EAF.

The limiting locations were determined by identifying the fatigue-sensitive locations, followed by comparison and ranking. As a result of the screening evaluation, there were other locations identified that are more limiting than the NUREG/CR-6260 locations. A consolidated tabulation for the ASME Code, Section III, pressure-boundary components and piping sentinel locations is as follows:

- RV outlet nozzles and support pads (RV shell-to-outlet nozzle welds)
- RV inlet nozzles and support pads (RV shell-to-inlet nozzle welds)
- RV main shell
- Pressurizer lower head and pressurizer surge line, 14-inch hot leg nozzle
- Steam generator tubes
- Safety injection, 6-inch cold leg nozzles
- Residual heat removal, 6-inch hot leg nozzles
- Normal / alternate charging, 3-inch cold leg nozzle

80-year EAF evaluations were prepared for the ASME Code, Section III, sentinel Class 1 components and piping locations using 40-year design transients. For sentinel ASME Code, Section III, Class 1 components and piping with environmentally-assisted fatigue usage (CUF_{en}) greater than 1.0, when using the analysis CUF, ASME Code, Section III, NB-3200 calculations were prepared to remove conservatisms used in the analysis, thereby reducing the CUF_{en} to less than 1.0. The CUF_{en} values for the RV shell-to-inlet nozzles and support pads, RV main shell, safety injection cold leg nozzles and residual heat removal hot leg nozzles are less than 1.0. Therefore, fatigue management is not required for these locations and transient sections.

The steam generator tubes are managed by the *Steam Generators* program (Section A1.10).

The remaining sentinel locations (i.e., RV outlet nozzle, pressurizer lower head and surge line hot leg nozzle, and normal / alternate charging cold leg nozzles) have been analyzed using flaw-tolerance evaluations conducted in accordance with the requirements of ASME Code, Section XI, Nonmandatory Appendix A or Appendix L, as applicable. Based upon the Appendix A or Appendix L flaw-tolerance evaluations, the effects of aging due to EAF for these locations will be managed through the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (Section A1.1) for the subsequent period of extended operation.

NUREG-2192 permits inspections as a management method for fatigue as long as a flaw tolerance evaluation is performed to determine the acceptable time between inspections. The ASME Code, Section XI, Appendix L crack growth evaluations are used in conjunction with calculated allowable flaw sizes to determine the required inspection interval for a postulated flaw at the bounding location. For a postulated initial flaw, crack growth is simulated, based upon exposure to specified numbers of transient cycles, until the flaw has either reached the allowable flaw depth or the end of the subsequent period of extended operation, whichever comes first.

The effects of aging due to EAF on the intended function(s) of the ASME Code, Section III Class 1 components and ASME Code, Section III Class 1 piping, that has been analyzed with ASME Code, Section XI, Appendix A or L evaluations, will be adequately managed by application of the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (Section A1.1). The *Fatigue Monitoring* program (Section A2.1) monitors and tracks the number of occurrences of each of the critical thermal and pressure transients that are used in the Appendix A and Appendix L flaw-tolerance evaluations to verify the numbers of cycles do not exceed the numbers of analyzed cycles and to validate that the inspection frequencies remain appropriate.

Thus, the effects of aging due to EAF on the intended function(s) will be adequately managed for the subsequent period of extended operation and the EAF TLAAs for these components are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A3.3.5 High-Energy Line-Break Analyses

A high-energy line break is not required to be postulated at a given high-energy piping location if the design CUF for that location, calculated in accordance with ASME Code, Section III, is less than or equal to 0.1. The Class 1 piping fatigue analyses are based on 40-year design transient cycles. The 40-year design cycles bound the 80-year projected cycles, so no CUF values increase. Since the CUF values for this piping remain unchanged, no new HELB locations are required for the subsequent period of extended operation. Therefore, the original HELB analyses remain valid for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.4 Environmental Qualification of Electric Equipment

Thermal, radiation, and cyclical aging analyses of electrical and I&C components, developed to meet 10 CFR 50.49 requirements, have been identified as time-limited aging analyses (TLAAs). The NRC nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49 require that an EQ program be established to demonstrate that certain electrical equipment located in harsh environments is qualified to perform applicable safety functions in those harsh environments after the effects of in-service aging. Harsh environments are defined as 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) or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

The *Environmental Qualification of Electric Equipment* program (A2.3) will manage the effects of aging for EQ equipment through the subsequent period of extended operation in accordance with 10 CFR 50.49(c)(1)(iii). The program meets the requirements of 10 CFR 50.49 for the applicable electrical equipment important to safety. Reanalysis of an aging evaluation to extend the qualifications of equipment is performed on a routine basis as part of the EQ program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, ongoing qualification, and corrective actions if acceptance criteria are not met.

If the qualification cannot be extended by reanalysis, the equipment must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner such that sufficient time is available to refurbish, replace, or requalify the equipment if the reanalysis is unsuccessful.

Unit 1 was evaluated against NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment,” Category II. The basis for Equipment Qualification is Inspection and Enforcement Bulletin (IEB) 79-01B, “Environmental Qualification of Class 1E Equipment,” and IEEE Standard 323-1971 “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations,” as codified by 10 CFR 50.49.

The Environmental Qualification of Electrical Equipment program ensures that the aging effects will be managed and that EQ equipment will continue to perform its intended function for the subsequent period of extended operation. Aging effects addressed by the EQ program will therefore be adequately managed for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

Accessible passive EQ electrical equipment within the scope of subsequent license renewal will be inspected at least once every ten years to identify EQ electrical equipment subjected to an adverse localized environment with the first inspection performed prior to the subsequent period of extended operation.

A3.5 Concrete Containment Tendon Prestress Analysis

Containment is provided by the Reactor Building, a post-tensioned, reinforced concrete structure composed of vertical cylinder walls and a shallow dome on a reinforced concrete base slab. The post-tensioning system of the Containment structure consists of dome tendons, hoop tendons, and vertical tendons. The cylinder walls are provided with 115 vertical tendons and 150 horizontal hoop tendons. The dome is provided with three layers of 33 tendons for a total of 99 tendons that intersect at 60^{o}.

The containment tendon prestressing forces were calculated during the original design considering the magnitude of the tendon relaxation and concrete creep and shrinkage over the 40-year life of the plant. The prestress of containment tendons decreases over time due to seating of anchorage losses, elastic shortening of concrete, creep of concrete, shrinkage of concrete, relaxation of prestressing steel, and friction losses. At the time of initial licensing, the magnitude of the prestress losses throughout the life of the plant was predicted and the estimated final effective preload at the end of 40 years was calculated for each tendon type based on log-linear extrapolation of creep, shrinkage, and relaxation results. The final effective preload was then compared with the minimum required preload to confirm the adequacy of the design.

Predicted lower limit lines and trend lines of measured prestressing forces have been established for applicable tendon groups through the subsequent period of extended operation. The PLL lines for each tendon group incorporated uncertainty adjustments consistent with Regulatory Guide 1.35.1. The prestressing forces are measured and plotted, and trend lines are developed, to ensure the average tendon group prestressing values remain above the respective minimum required values until the next scheduled surveillance. The predicted lower limit force values and regression analyses, utilizing actual measured tendon forces, are used to evaluate the acceptability of the Containment structure to perform its intended function over the life of the plant.

The effects of aging related to prestress forces on the intended function(s) of the containment tendon prestressing system will be adequately managed by the *Concrete Containment Unbonded Tendon Prestress* program (Section A2.4) and *ASME Section XI, Subsection IWL* program (Section A1.31) for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A3.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis

A3.6.1 Containment Liner Plate

The original design analysis for the containment liner plate and penetration sleeves included a fatigue waiver which demonstrated that all six requirements of the ASME Code were met, providing the basis to conclude that no fatigue analysis was required for these components. The anticipated startup/shutdown cycles in the fatigue waiver were extrapolated for an 80-year operating period and demonstrate that the six conditions in the ASME Code continue to be met and therefore, no fatigue analysis is required through the subsequent period of extended operation. The fatigue waiver for the Containment liner and penetration sleeves was revised for 80 years and has been projected to the end of the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

A3.6.2 Metal Containment

Not applicable.

A3.6.3 Containment Penetrations Fatigue Analysis

The Reactor Building main steam penetrations were designed in accordance with ASME Section III, 1974 Edition through Winter, 1975 Addenda and identified as a TLAA. No other Reactor Building penetrations meet the criteria to be considered TLAAs. The Reactor Building main steam penetrations consist of three main components. The first is the penetration sleeve, which was evaluated with the containment liner (Section A3.6.1). The remaining components include the section of process pipe passing through the penetration and the attachment assemblies both inside and outside of the containment wall that connect the process pipe to the sleeve. Together, the two remaining parts of the main steam penetrations make up the main steam penetrations internals and have a design analysis that demonstrates the 40-year design transient cycles continue to bound the 80-year projected cycles. Therefore, the TLAA will remain valid for the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

A3.7 Other Plant-Specific Time-Limited Aging Analyses

Those that were identified as plant-specific TLAAs are evaluated in the following Subsections:

- Crane Load Cycle Limits (Section A3.7.1)
- Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis (Section A3.7.2)
- Leak-Before-Break (Section A3.7.3)
- Steam Generator Tube Wear Evaluation (Section A3.7.4)

A3.7.1 Crane Load Cycle Limits

The design standard number of full-capacity lifts exceeds the number projected for each machine for an 80-year life, even with a significant number of unforeseen lifts. The lifting machine designs therefore remain valid for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.7.2 Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis

Fatigue crack initiation and growth in reactor coolant pump (RCP) flywheels was evaluated for the subsequent period of extended operation and documented in PWROG-17011-NP, “Update for Subsequent License Renewal: WCAP-14535A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,” and WCAP-15666-A, “Extension of Reactor Coolant Pump Motor Flywheel Examination.” which confirms that the analysis described in WCAP-14535-A and WCAP-15666-A remains valid. The fatigue crack-growth evaluation assumed 6000 cycles of RCP start/stop, which bounds the 2,000 cycles projected for 80 years of operation. The RCP fatigue-growth analysis remains valid for the subsequent period of extended operation and is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.7.3 Leak-Before-Break

10 CFR 50 Appendix A, Criterion 4 allows use of leak-before-break (LBB) technology for excluding the dynamic effects of postulated ruptures in primary coolant loop piping from the design basis in PWRs. WCAP-13206, Revision 1, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Virgil C. Sumer Nuclear Power Plant,” demonstrated compliance with LBB technology for the reactor coolant system piping by evaluation based on loading, pipe geometry and fracture toughness considerations. Fatigue Crack Growth (FCG) was shown to not be a concern for primary loops. WCAP-13206, Revision 2 reconciled the LBB analysis with the loop ’A’ hot leg replacement spool piece and welds, demonstrating that previous LBB conclusions remained valid, and the dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis. WCAP-13206, Revision 3 addresses

mechanical stress improvement processes on the loop 'B' and 'C' RV outlet nozzles, and confirmed the LBB analysis for initial license renewal (60 years).

The FCG evaluation performed for the subsequent license renewal LBB evaluation is a defense in depth evaluation to demonstrate that small surface flaws do not become through-wall flaws over the life of the plant. The LBB evaluation was updated in WCAP-13206, Revision 4 to account for the effects of a mechanical stress improvement process, and to demonstrate that dynamic effects of reactor coolant primary loop pipe breaks need not be considered in the structural design basis. These changes were evaluated in WCAP-13206 Revision 4 to ensure that the existing LBB evaluation conclusions remain applicable for 80 years of operation.

The assessment performed in WCAP-13206 Revision 4, determined that the crack stability results, fracture toughness, and fatigue crack growth results are acceptable for the 80-year subsequent period of extended operation. Therefore, the LBB analysis has been projected to the end of the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A3.7.4 Steam Generator Tube Wear Evaluation

Steam generator (SG) tube wear was calculated as part of the replacement steam generator design in WNEP-9314, “Delta 75 Steam Generator Flow Induced Vibration and Tube Wear / Corrosion Evaluation.” Tube wear calculations were performed, considering additional years of continued wear through the subsequent period of extended operation. The evaluation, using a linear adjustment, shows the updated subsequent period of extended operation wear value is below the 40% through-wall wear depth of 16 mils, which is the Technical Specification depth at which tubes are plugged for tube wear.

The wear evaluation has been projected to the end of the subsequent period of extended operation. Nonetheless, the steam generator tube wear is managed by the *Steam Generators* program (Section A1.10) and is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

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A4 Subsequent License Renewal Commitments

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
1	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program	The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require volumetric inspection of the pressurizer surge line hot leg nozzle every 48 years for management of EAF. Based on satisfactory results from the last inspection performed in Q2 1993, the next inspection will be performed by Q2 2041.	B2.1.1	Program enhancement for SLR will be implemented by Q2 2041.
2	*Water Chemistry* program	The *Water Chemistry* program is an existing preventive program that is credited.	B2.1.2	Ongoing
3	*Reactor Head Closure Stud Bolting* program	The *Reactor Head Closure Stud Bolting* program is an existing condition monitoring program that will be enhanced as follows: 1. Procurement documents for reactor head closure studs will be revised to incorporate guidance from RG 1.65, Revision 1 and NUREG-2191, Section XI.M3, to add a limit for the maximum measured yield strength of 150 ksi and a limit for maximum tensile strength of 170 ksi.	B2.1.3	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
4	*Boric Acid Corrosion* program	The *Boric Acid Corrosion* program is an existing condition monitoring program that is credited.	B2.1.4	Ongoing
5	*Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program	The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is an existing condition monitoring program that is credited.	B2.1.5	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
6	*Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program	The *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program is an existing condition monitoring program that is credited.	B2.1.6	Ongoing
7	*PWR Vessel Internals* program	The *PWR Vessel Internals* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to include a list of the components that require inspections for the Primary, Expansion, and Existing Programs categories specified in MRP-227, Revision 1-A. 2. Procedure will be revised to require additional spring height measurements prior to the SPEO to establish the core barrel hold down spring height and determine if replacement of the core barrel hold down spring is required.	B2.1.7	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
8	*Flow-Accelerated Corrosion* program	The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that is credited.	B2.1.8	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
9	*Bolting Integrity* program	The *Bolting Integrity* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to specify instructions for performing inspections of pressure boundary bolting for locations that preclude detection of joint leakage including bolting in submerged environments, bolting for air or gas systems, and bolting for piping systems not normally pressurized as follows: a. Submerged closure bolting is visually inspected for loss of material during maintenance activities. In this case, bolt heads are inspected when made accessible, and bolt threads are inspected when joints are disassembled. In each 10-year period during the subsequent period of extended operation, a representative sample of bolt heads and threads is inspected up to a maximum of 25 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 25 bolt heads and threads over a 10-year period, then periodic pump vibration measurements are taken and trended. b. For air or gas systems, inspections are performed consistent with that of submerged closure bolting. Closure bolting for air or gas systems is visually inspected for loss of material during maintenance activities. In this case, bolt heads are visually inspected when made accessible, and bolt threads are visually inspected when joints are disassembled. In each 10-year period during the subsequent period of extended operation, a representative sample of bolt heads and threads is inspected up to a maximum of 25 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 25 bolt heads and threads over a 10-year period, then soap bubble testing will be performed. c. For piping systems not normally pressurized, the torque of the bolting will be checked to the extent that the closure bolting is not loose. In each 10-year period during the subsequent period of extended operation, a representative sample of bolt heads and threads is inspected up to a maximum of 25 bolts for each material and environment combination. 2. Procedure(s) will be revised to: a. Include inspections of pressure-retaining bolting in inaccessible areas when they become accessible by means such as excavation, dewatering, or shielding/barrier removal. b. Include a requirement during opportunistic maintenance activities to document the condition of bolt heads and threads. 3. Procedure(s) will be revised to specify inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task.	B2.1.9	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
9	*Bolting Integrity* program	4. Procedure(s) will be revised to evaluate sampling-based inspections against plant-specific acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies will be evaluated and adjusted as determined by the Corrective Action Program. Bolting that is unsuitable for continued use will be replaced. If the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment, additional inspections will be conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections will be determined in accordance with the Corrective Action Program; however, there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material and environment combination is inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material and environment combination and will be completed within the 10-year inspection interval in which the original inspection was conducted.	B2.1.9	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
10	*Steam Generators* program	The *Steam Generators* program is an existing condition monitoring program that is credited.	B2.1.10	Ongoing
11	*Open-Cycle Cooling Water* program	The *Open-Cycle Cooling Water* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that will be enhanced as follows: 1. A plant modification will be implemented to the safety-related portion of service water piping in the Service Water Pump House that provides cooling water to the cooling coils to eliminate concerns with recurring internal corrosion. Specifically, the modification will either isolate and drain or physically remove the aforementioned safety-related portion of service water piping. 2. A plant modification will be implemented to replace the carbon steel service water return valves from the diesel generator coolers with stainless steel valves and fittings to be more resistant to cavitation damage, and to modify the piping configuration to reduce cavitation. 3. Procedure(s) will be revised to specify that inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task.	B2.1.11	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
11	*Open-Cycle Cooling Water* program	4. Procedure(s) will be revised to specify that additional inspections will be performed if any inspection results do not meet the acceptance criteria unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less.	B2.1.11	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
12	*Closed Treated Water Systems* program	The *Closed Treated Water Systems* program is an existing condition monitoring and mitigative program that will be enhanced as follows: 1. Procedure(s) will be revised to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections be completed for the various sample populations (each material, water treatment program, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% 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 will be inspected. The inspections will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. 2. Procedure(s) will be revised to specify inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. 3. Procedure(s) will be revised to specify that, where practical, the rate of any degradation is evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection. 4. Procedure(s) will be revised to specify that additional inspections will be performed if any inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.	B2.1.12	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
13	*Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program	The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to require: • Visual inspections of rails, bridges, structural members, and structural components for loss of material due to general corrosion; deformation; cracking, and wear. • Visual inspections of rails, bolted connections for loss of material due to general corrosion; cracking; and loose or missing bolts or nuts, and other conditions indicative of loss of preload.	B2.1.13	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
14	*Compressed Air Monitoring* program	The *Compressed Air Monitoring* program is an existing preventive and condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to require Turbine Building instrument air dryer outlet dew point readings greater than zero be documented in the Corrective Action Program and evaluations performed for results that do not satisfy established criteria as identified in the applicable procedures. 2. Procedure(s) will be revised to specify inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task.	B2.1.14	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
15	*Fire Protection* program	The *Fire Protection* program is an existing condition monitoring and performance monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to provide guidance for detection of loss of material, cracking, holes, and gaps during the visual inspections of fire dampers, and to determine the acceptability of the findings. 2. Procedure(s) will be revised to provide guidance to ensure that inspection results for fire protection components are trended to provide for timely detection of aging effects so that the appropriate corrective actions can be taken. Where practical, identified degradation will be projected until the next scheduled inspection. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. 3. Procedure(s) will be revised to provide guidance for evaluating projected inspection results. For results that will fail to meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the Corrective Action Program.	B2.1.15	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	The *Fire Water System* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to require follow-up volumetric wall thickness examinations be performed when surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition are identified during visual inspections. 2. Procedure(s) will be revised to require sprinklers that have been in service for 75 years be replaced or representative samples from one or more sample areas be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing and repeated at 5-year intervals. 3. Procedure(s) will be revised for wet pipe sprinkler systems to include a one-time test of sprinklers that have been exposed to water. A sample of 3% or a maximum of ten sprinklers with no more than four sprinklers per structure will be tested. Testing will be based on a minimum time in service of fifty years and severity of operating conditions for each population. 4. Procedure(s) will be revised to perform annual main drain tests on standpipe systems with automatic water supplies in the scope of subsequent license renewal as required by NFPA-25 (2011 Edition), Chapter 13, Valves, Valve Components, and Trim. 5. Procedure(s) will be revised to require flow tests every 5 years at the hydraulically most remote hose connections of each zone of automatic standpipe systems within the scope of subsequent license renewal as required by NFPA-25 (2011 Edition), Section 6.3.1, Flow Tests. 6. Procedure(s) will be revised to require a main drain test be conducted annually at each water-based fire protection system riser to determine whether there has been any change in the condition of the water supply piping and control valves. Acceptance criteria will be based upon monitoring flowing pressures from test to test to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. If required, the Corrective Action Program will determine the cause and any necessary corrective action. 7. Procedure(s) will be revised to specify inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. 8. Procedure(s) will be revised to provide inspection guidance related to lighting, distance and offset for non-ASME Code inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used.	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	9. Procedure(s) will be revised to perform the following augmented testing and inspections of 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. The augmented tests and inspections indicated below will be conducted on piping segments that cannot be drained or piping segments that allow water to collect. a. In each five-year interval, beginning five 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% of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect. If the results of a 100% internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary. b. In each five-year interval of the subsequent period of extended operation, 20% of the length of piping segments that cannot be drained or piping segments that allow water to collect will be subject to volumetric wall thickness inspections. Measurement points will be obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, MIC). The 20% of piping that is inspected in each five-year interval will be in different locations than previously inspected piping. 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. 10. Procedure(s) will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits.	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	11. Procedure(s) will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow every five years. Follow-up volumetric examinations will be performed if internal visual inspections detect an unexpected level of degradation due to corrosion product deposition. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following: a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have internal visual inspections of piping by opening a flushing connection at the end of one main and removing a sprinkler toward the end of one branch line, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected. b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have internal visual inspections of piping by removing a sprinkler nozzle from the most remote branch line from the source of water that is not equipped with the inspector's test valve, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. c. Deluge systems - deluge systems in scope for subsequent license renewal will have internal visual inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. 12. Procedure(s) will be revised to require results of sampling-based inspections be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. 13. Procedure(s) will be revised to require that if a flow test (i.e., NFPA 25 Section 6.3.1) or a main drain test (i.e., NFPA Section 13.2.5) does not meet acceptance criteria due to current or projected degradation (i.e., trending) additional tests are conducted. The number of increased tests will be determined in accordance with the Corrective Action Program; however, there will be no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections will be completed within the interval (i.e., 5 years, annual/refueling) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of tests.	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
17	*Outdoor and Large Atmospheric Metallic Storage Tanks* program	The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is a new condition monitoring program that will manage the aging effects of cracking and loss of material on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil with internal pressures approximating atmospheric pressure. The program manages cracking and loss of material by conducting periodic external visual and surface examinations and periodic thickness measurements of tank bottoms. Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.17	Program will be implemented and inspections or tests begin 10 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
18	*Fuel Oil Chemistry* program	The *Fuel Oil Chemistry* program is an existing mitigative and condition monitoring and preventive monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to drain, clean internally to the extent practical, visually inspect internal surfaces (if physically possible), and perform tank bottom thickness measurements for the following tanks: a. Diesel driven fire pump fuel oil day tank b. Diesel generator fuel oil day tanks c. Diesel generator fuel oil storage tanks The procedure(s) will require that if evidence of degradation is observed during visual inspection, or if visual inspection is not possible, volumetric inspections will be performed. The draining, cleaning and inspection of each tank will be performed at least once during the 10-year period prior to the subsequent period of extended operation and at least once every 10 years during the subsequent period of extended operation. 2. Procedure(s) will be revised to require an Engineering evaluation be performed to evaluate and trend visual and volumetric (if degradation is detected during inspections) tank inspection results. Unacceptable inspection results will be documented in the Corrective Action Program. Thickness measurements will be evaluated against the design thickness and corrosion allowance. The rate of degradation will be evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection frequency will be adjusted, as necessary, based on the projection. 3. Procedure(s) will be revised to periodically drain accumulated water from the diesel driven fire pump fuel oil day tank.	B2.1.18	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
19	*Reactor Vessel Material Surveillance* program	The *Reactor Vessel Material Surveillance* program is an existing condition monitoring program that is credited.	B2.1.19	Ongoing
20	*One-Time Inspection* program	The *One-Time Inspection* program is a new 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 material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action. Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.20	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
21	*Selective Leaching* program	The *Selective Leaching* program is a new condition monitoring program that will monitor components constructed of materials which are susceptible to selective leaching. The selective leaching program includes a one-time inspection for susceptible components exposed to closed cycle cooling water and treated water environment when plant-specific operating experience has not revealed selective leaching in these environments, as well as opportunistic and periodic inspections for susceptible components exposed to raw water, waste water, and soil (which may include groundwater) environments when plant specific operating experience has revealed selective leaching in these environments. Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.21	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
22	*ASME Code Class 1 Small-Bore Piping* program	The *ASME Code Class 1 Small-Bore Piping* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to specify the following: • Perform one-time inspections of small-bore piping using the program methods and acceptance criteria. • Perform periodic inspections of reactor coolant pump seal injection to thermal barrier nozzle welds using the program methods, frequencies, and acceptance criteria. • Evaluate the results to determine if additional or periodic examinations are required. • Perform any required additional or periodic inspections. 2. Procedure(s) will be revised to require a subsequent re-examination after any component containing flaws or relevant conditions is accepted for continued service by analytical evaluation, in order to meet the intent of ASME Code, Section XI, Subarticle IWB-2420. 3. Procedure(s) will be revised to require examination results be evaluated in accordance with ASME Code, Section XI, Paragraph IWB-3132. 4. Procedure(s) will be revised to require corrective actions include examinations of additional ASME Code Class 1 small-bore piping welds, in order to meet the intent of ASME Code, Section XI, Subarticle IWB-2430.	B2.1.22	Program will be enhanced and inspections completed within 6 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior of extended operation.
23	*External Surfaces Monitoring of Mechanical Components* program	The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to specify that walkdowns will be performed at a frequency not to exceed one refueling cycle. Since some surfaces are not readily visible during both plant operations and refueling outages, surfaces will be inspected when they are made accessible and at intervals that would ensure the components' intended functions are maintained. 2. Procedure(s) will be revised to specify that visual inspections of elastomers and flexible polymers will cover 100% of accessible component surfaces. The minimum surface area for tactile inspections of elastomers and flexible polymers will be at least 10% of the accessible surface area.	B2.1.23	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
23	*External Surfaces Monitoring of Mechanical Components* program	3. Procedure(s) will be revised to specify the following to manage cracking of copper alloy (>15% Zn) components and cracking and loss of material of insulated outdoor/indoor components exposed to condensation populations: a. In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed. Examinations for cracking will be performed from the copper alloy (>15% Zn) component population every 10 years. Examinations are conducted on 20% of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components is inspected. For insulated outdoor components and indoor components exposed to condensation, following insulation removal, a minimum of 20% of the in-scope piping length, or 20% of the surface area for components whose configuration does not conform to a one-foot axial length determination is inspected for loss of material and cracking. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components for each material type is inspected. The new procedure will specify that the inspections focus on the components most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin. b. Additional inspections will be performed if any sampling-based inspections to detect cracking in copper alloy (>15% Zn) components do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted. 4. Procedure(s) will be revised to evaluate and project the rate of degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection. 5. Procedure(s) will be revised to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.	B2.1.23	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
24	*Flux Thimble Tube Inspection* program	The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that is credited.	B2.1.24	Ongoing
25	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program	The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to specify inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. 2. Procedure(s) will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. Adequate lighting will be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. For internal inspections, accessible surfaces will be inspected. If inspecting piping internal surfaces, a minimum of one linear foot will be inspected, if accessible. Cleaning will be performed as necessary to allow for a meaningful examination. If protective coatings are present, the condition of the coating will be documented. 3. Procedure(s) will be revised to specify the following: a. In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 25 components per population will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions. b. The rate of degradation will be evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g.: selection, size, frequency) will be adjusted as necessary based on the projection.	B2.1.25	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
25	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program	c. Additional inspections will be performed if any sampling-based inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination. The additional inspections will be completed within the interval (e.g.: refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. 4. Procedure(s) will be revised to specify that, where practical, acceptance criteria are quantitative (e.g.: minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.	B2.1.25	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
26	*Lubricating Oil Analysis* program	The *Lubricating Oil Analysis* program is an existing preventive program that will be enhanced as follows: 1. Procedure(s) will be revised to require periodic sampling and testing of the reactor building chiller oil for water and particulates. Procedure(s) will include water and particulate limits. 2. Procedure(s) will be revised to include: Water Testing: Water in oil will be monitored with the Visual Crackle Test or other first level water content test. The target value for water concentration will be less than or equal to 500 ppm (0.05%). If water content is nominally greater than 500 ppm (i.e., it fails the crackle test or other first level water content test), a confirmatory water analysis consistent with ASTM D6304 (Karl-Fischer titration test) or equivalent method will be performed to determine if the water content is within the limits specified in plant procedures. Phase-separated water in any amount is not acceptable. Particulate limits: Procedure(s) will be revised to specify established particulate limits that are based on equipment manufacturer's recommendations or industry standards.	B2.1.26	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
26	*Lubricating Oil Analysis* program	3. Procedure(s) will be revised to require sampling lubricating oil for particulate and performance of a particle count analysis. 4. Procedure(s) will be revised to require sampling and testing following periodic oil changes or on a schedule consistent with equipment manufacturer's recommendations or industry standards. 5. Procedure(s) will be revised to require that water and particulate test results are monitored to identify adverse trends that require corrective action(s). 6. Procedure(s) will be revised to require initiating a condition report if the data collected exceed an alert limit or indicate an unexpected negative trend. Corrective actions will be determined by the Corrective Action Program, and may include increased monitoring, corrective maintenance, further laboratory analysis, and engineering evaluation of the system.	B2.1.26	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
27	*Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program	The *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program is an existing condition monitoring program that is credited.	B2.1.27	Ongoing
28	*Buried and Underground Piping and Tanks* program	The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to specify that the limiting critical potential for the cathodic protection system should not be more negative than -1,200 mV to prevent damage to the coating. 2. The nine cathodic protection systems will be refurbished and upgraded to improve reliability. The refurbishment and upgrades will be implemented five years prior to entering the subsequent period of extended operation.	B2.1.28	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
29	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is a new condition monitoring program that will manage loss of coating integrity of the in-scope components, exposed to closed-cycle cooling water, raw water, and treated water environments, that can lead to loss of base material or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris. The program will manage loss of material or cracking for cementitious coatings/linings. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.	B2.1.29	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
30	*ASME Section XI, Subsection IWE* program	The *ASME Section XI, Subsection IWE* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to require one-time supplemental surface examinations (or other applicable technique; e.g., EVT-1) to detect cracking due to SCC of the Containment pressure-retaining portions of the stainless steel fuel transfer tube assembly and 20% of the stainless steel or dissimilar metal welds associated with high temperature piping penetration sleeves, (i.e., penetration sleeves with temperatures greater than or equal to 140 degrees F). The one-time supplemental surface examinations will be performed prior to the subsequent period of extended operation to confirm the absence of cracking due to SCC. If SCC is detected as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the Corrective Action Program.	B2.1.30	Program enhancements will be implemented 6 months prior to the subsequent period of extended operation and if triggered by plant-specific operating experience, a one-time supplemental volumetric examination by sampling randomly-selected as well as focused locations susceptible to loss of thickness due to corrosion of containment shell or liner that is inaccessible from one side is completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
30	*ASME Section XI, Subsection IWE* program	2. Procedure(s) will be revised to require a one-time volumetric examination of metal liner surfaces that are inaccessible from one side, only if triggered by plant-specific operating experience. The trigger for this supplemental examination will be plant-specific occurrence or recurrence of measurable metal liner corrosion (base metal material loss exceeding 10% of nominal plate thickness) on the inaccessible side or areas, identified since the date of issuance of the initial renewed license. This supplemental volumetric examination will consist of a sample of one-foot square locations that include both randomly-selected and focused areas most likely to experience degradation based on operating experience and/or other relevant considerations such as environment. This supplemental volumetric examination will occur within two refueling outages after identifying the triggering for the examination. Any identified degradation will be addressed in accordance with the applicable provisions of the *ASME Section XI, Subsection IWE* program. The sample size, locations, and any needed scope expansion (based on findings) for the supplemental volumetric examinations will be determined on a plant-specific basis to demonstrate statistically with 95% confidence that 95% of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than 10% loss of nominal thickness. There has been no triggering operating experience for liner corrosion since the date of issuance of the initial renewed license. 3. Procedure(s) will be revised to specify that successive inspections be sequenced, evaluated, and re-examined in accordance with ASME Code, Section XI, Subsection IWE, Article IWE-2420. Examination results will be compared with recorded results of prior inservice examinations and evaluated for acceptance in accordance with ASME Code, Section XI, Subsection IWE, Article IWE-3120.	B2.1.30	Program enhancements will be implemented 6 months prior to the subsequent period of extended operation and if triggered by plant-specific operating experience, a one-time supplemental volumetric examination by sampling randomly-selected as well as focused locations susceptible to loss of thickness due to corrosion of containment shell or liner that is inaccessible from one side is completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
31	*ASME Section XI, Subsection IWL* program	The *ASME Section XI, Subsection IWL* program is an existing condition monitoring program that is credited.	B2.1.31	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

<table>
<tr><th>#</th><th>Program</th><th>Commitment</th><th>AMP</th><th>Implementation</th></tr>
<tr><td>32</td><td>ASME Section XI, Subsection IWF program</td><td>The ASME Section XI, Subsection IWF program is an existing condition monitoring program that will be enhanced as follows:
1. Procedure(s) will be revised to include class MC component supports in the scope of the program.
2. Procedure(s) will be revised to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.
3. Procedure(s) will be revised to require ASTM A325 and ASTM A490 bolts and associated nuts and washers to be stored in closed containers to protect them from dirt and corrosion. Additionally, the closed containers will be required to be stored in a protected shelter (Storage Level B or C) until use.
4. Procedure(s) will be revised to specify a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation.
5. Procedure(s) will be revised to require that if a component support does not exceed the acceptance standards of IWF-3400 but is repaired to as-new condition, the sample will be increased or modified to include another support that is representative of the remaining population of supports that were not repaired.
6. Procedure(s) will be revised to include the additional unacceptable conditions indicated below that are not specified in IWF-3410(a) and to specify any unacceptable conditions may be accepted with a documented technical basis.
a. Loss of material due to corrosion or wear.
b. Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support.
c. Cracked or sheared bolts, including high-strength bolts, and anchors.
d. Cracks.
The above conditions may be accepted provided the technical basis for their acceptance is documented.</td><td>B2.1.32</td><td>Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation. The one-time inspections are to begin no earlier than 5 years prior to the subsequent period of extended operation and are to be completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.</td></tr>
<tr><td>33</td><td>10 CFR 50, Appendix J program</td><td>The 10 CFR 50, Appendix J program is an existing performance monitoring program that is credited.</td><td>B2.1.33</td><td>Ongoing</td></tr>
</table>

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
34	*Masonry Walls* program	The *Masonry Walls* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to include, into the scope of the program, masonry walls in the Auxiliary Service Building and Water Treatment Building. 2. Procedure(s) will be revised to require inspection for 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. 3. Procedure(s) will be revised to specify that the interval between inspections does not exceed five years.	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
35	*Structures Monitoring* program	The *Structures Monitoring* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to include inspection of the following structures within the scope of subsequent license renewal: Auxiliary Service Building; alternate seal injection diesel generator (XEG0101) and control panel (XPN5587) (foundations and anchors); carbon dioxide tank (foundation and anchors); Circulating Water Intake Structure (includes Fire Service Pumphouse); the concrete pad supporting piping and equipment for filling Emergency Diesel Generator fuel oil tanks; 115 kV yard equipment (supports, foundations and anchors) from the plant including transformer XTF-4 and voltage regulator, XTF-6 and electrical switch XES-8, through and including electrical circuit switcher XES-4; electrical manholes EMH(s) 9, 11, 31, 32, 46, 47, 70, 72, 74, 75, and 76; sodium hydroxide tank (foundation and anchors); Unit 1 Relay House; and the Water Treatment Building. Baseline inspections for the added structures will be performed under the enhanced program to establish quantitative inspection data prior to conduct of periodic inspections in the subsequent period of extended operation. 2. Procedure(s) will be revised to include inspection of the following structural components: battery racks, cable bus enclosures and tap box enclosures (external surfaces and supports and support foundations), cable trays and conduits, cable trenches and covers (between Unit 1 Relay House, the Substation Relay House, and the 230 kV breaker XCB-8892), 230 kV substation lightning arrestor poles and foundations, doors, elastomeric materials, electrical duct banks, louvers, masonry wall edge support and bracing members, panels and other enclosures, penetration seals, pipe whip restraints and jet impingement shields (includes guard pipes used as shields against spray or jet impingement), sump and pool liners, switchyard bus supports, transmission towers, racks, trash racks (for Circulating Water Intake Structure), and tube tracks. 3. Procedure(s) will be revised to require storage of ASTM A325 and ASTM A490 bolts and associated nuts and washers be in closed containers to protect them from dirt and corrosion and the closed containers be stored in a protected shelter (Storage Level B or C) until use.	B2.1.35	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
35	*Structures Monitoring* program	4. Procedure(s) will be revised to require inspection of structural steel bracing and edge supports associated with masonry walls for deflection or distortion, loose bolts, and loss of material due to corrosion. 5. Procedure(s) will be revised to require inspection of elastomeric materials including structural sealants for cracking, loss of material, and hardening include the use of tactile inspection to detect hardening if the intended function is suspect. 6. Procedure(s) will be revised to require, where leakage volumes allow, monitoring and trending of through wall leakage or water infiltration and leaching deposits for volume and chemistry (for pH, mineral, calcium, chloride, sulfate and iron content) to evaluate any potential effect on the concrete or reinforcing steel. 7. Procedure(s) will be revised to require monitoring of aluminum and stainless steel structural components such as louvers, cable trays, conduits, and structural supports for loss of material and cracking due to SCC that could lead to the reduction or loss of their intended function. 8. Procedure(s) will be revised to require accounting for seasonal variations in the sampling of groundwater (e.g., quarterly monitoring every 5th year). 9. Procedure(s) will be revised to indicate excavation and focused examination of a sample of below grade concrete exposed to groundwater, or other measures, may be necessary every five years to detect potential concrete degradation if the groundwater in contact with the structures is determined to be aggressive. 10. Procedure(s) will be revised to require indications of groundwater infiltration or through-concrete leakage require assessment for aging effects which may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. 11. Procedure(s) will be revised to incorporate the ACI 349.3R Chapter 5 'second-tier' evaluation criteria as quantitative acceptance criteria for concrete surfaces. 12. Procedure(s) will be revised to require evaluation criteria for steel structures be based on the judgment of a qualified structural engineer using the AISC Specification for Structural Steel Buildings and Code of Standard Practice. 13. Procedure(s) will be revised to specify: a. Loose nuts and bolts are not acceptable (unless accepted by engineering evaluation). b. Structural sealants are acceptable if observed loss of material, cracking, and hardening will not result in loss of sealing. c. Sliding surfaces are acceptable if (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.	B2.1.35	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
36	*Inspection of Water Control Structures Associated with Nuclear Power Plants* program	The *Inspection of Water Control Structures Associated with Nuclear Power Plants* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to include inspection of steel elements including miscellaneous steel, and structural bolting associated with water control structures. 2. Procedure(s) will be revised to require ASTM A325 and ASTM A490 bolts and associated nuts and washers to be stored in closed containers to protect them from dirt and corrosion. Additionally, the closed containers will be required to be stored in a protected shelter (Storage Level B or C) until use. 3. Procedure(s) will be revised to specify the parameters to be monitored and inspected for concrete structures include those described in ACI-201.1R and ACI-349.3R and include monitoring conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage. 4. Procedure(s) will be revised to specify steel components and bolting are inspected for loss of material due to corrosion, loose bolts, missing or loose nuts, other conditions indicative of loss of bolt preload, and cracked concrete around anchor bolts. 5. Procedure(s) will be revised to specify earthen structures are inspected for depressions, sinkholes, slope stability, and animal burrows. 6. Procedure(s) will be revised to require periodic determination and assessment of the bottom elevations of the Service Water Pond to ensure required water volume is maintained. 7. Procedure(s) will be revised to require qualifications of inspection and evaluation personnel are consistent with ACI 349.3R for reinforced concrete water-control structures. 8. Procedure(s) will be revised to specify special inspections immediately following the occurrence of significant natural phenomena, such as large floods, hurricanes, tornadoes, or intense local rainfalls. 9. Procedure(s) will be revised to require indications of groundwater infiltration or through-concrete leakage be assessed for aging effects. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water. 10. Procedure(s) will be revised to require the underwater portions of the Service Water Pumphouse be included in the underwater structural inspections using a diver or dewatering, performed on a frequency not to exceed five years. 11. Procedure(s) will be revised to require the potential for aging affects for inaccessible, below-grade concrete structural elements be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.	B2.1.36	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
36	*Inspection of Water Control Structures Associated with Nuclear Power Plants* program	12. Procedure(s) will be revised to specify examination of representative samples of the exposed portions of the below-grade concrete when excavated for any reason. 13. Procedure(s) will be revised to specify quantitative measurements and qualitative information be recorded and trended for findings exceeding the acceptance criteria for the applicable parameters monitored or inspected. 14. Procedure(s) will be revised to incorporate the ACI 349.3R Chapter 5 'second-tier' evaluation criteria as quantitative acceptance criteria for concrete surfaces. 15. Procedure(s) will be revised to specify engineering evaluations are documented and based on codes, specifications and standards such as AISC Specifications and those referenced in the plant's current licensing basis.	B2.1.36	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
37	*Protective Coating Monitoring and Maintenance* program	The *Protective Coating Monitoring and Maintenance* program is an existing condition monitoring program that is credited.	B2.1.37	Ongoing
38	*Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to add the requirement to identify adverse localized environments through plant operational experience reviews, communication with maintenance, operations, and radiation protection personnel, and the use of environmental surveys for determining each of the most limiting cable and connection electrical insulation plant environments (e.g.: caused by temperature, radiation, moisture, or contamination.) 2. Procedure(s) will be revised to include a list of structures/areas to perform/conduct the visual inspections of cables and connections. 3. Procedure(s) will be revised to add the requirement to perform a review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation.	B2.1.38	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
38	*Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	4. Procedure(s) will be revised to add a description of testing methodology: Should testing be deemed necessary based on unacceptable visual indications of surface anomalies, a sample size of 20% of each cable and connection insulation material type found within the adverse localized environment with a maximum sample size of 25 will be tested. The following factors will be considered in the development of the cable and connection insulation test sample: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location (high temperature, high humidity, vibration, etc.), and insulation material. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. The technical basis for the sample selected is provided. 5. Procedure(s) will be revised to specify the visual inspection be performed prior to the period of extended operation and at least once every 10 years thereafter. 6. Procedure(s) will be revised to require the test results for electrical cable and connection insulation material be verified to confirm they are within the acceptance criteria identified in the procedure(s). 7. Procedure(s) will be revised to add the requirement to include the performance of an Engineering evaluation of unacceptable test results and visual indications of cable and connection electrical insulation abnormalities. The evaluation will consider 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).	B2.1.38	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
39	*Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program	The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program is an existing performance monitoring program that is credited.	B2.1.39	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
40	*Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to inspect and dewater, if required, the in-scope manholes after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. 2. Procedure(s) will be revised to clarify that the frequency of manhole inspections will occur at least once a year.	B2.1.40	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
41	*Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the effects of reduced electrical insulation resistance or degraded dielectric strength of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), instrument and control cables, exposed to significant moisture. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.	B2.1.41	Program will be implemented 6 months prior to the subsequent period of extended operation.
42	*Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), low-voltage power cables (operating voltage less than 2 kV), potentially exposed to significant moisture. Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.42	Program will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
43	*Fuse Holders* program	The *Fuse Holders* program is a new condition monitoring program that will manage the aging effect of increased electrical resistance of connection of the metallic clamps and reduced electrical insulation resistance of the fuse holder electrical insulation material. Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.43	Program will be implemented 6 months prior to the subsequent period of extended operation.
44	*Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that consists of a representative sample of non-EQ, in scope, electrical cable connections (metallic parts) tested prior to the subsequent period of extended operation to provide an indication of the integrity of the cable connections. The results will be evaluated to determine if there is a need for subsequent periodic testing on a 10-year frequency. Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.44	Program will be implemented 6 months prior to the subsequent period of extended operation.
45	*High-Voltage Insulators* program	The *High-Voltage Insulators* program is a new condition monitoring program that visually inspects high voltage insulator surfaces and metallic parts at least once every two years initially with the frequency adjusted based on plant specific operating experience. For high-voltage insulators that are coated, the visual inspection will be performed at least once every five years. Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.45	Program will be implemented 6 months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
46	*Fatigue Monitoring* program	The *Fatigue Monitoring* program is an existing preventive program that will be enhanced as follows: 1. Procedure(s) will be revised to require: a. Transient cycles associated with the ASME Code, Section XI, Appendix A and L fatigue-sensitive locations be identified and tracked each ten-year interval. b. A surveillance limit be established for transient cycles associated with the ASME Code, Section XI, Appendix A and L fatigue-sensitive locations and corrective actions be initiated prior to exceeding the ASME Code, Section XI, Appendix A or L analyses transient cycle assumptions. 2. Procedure(s) will be revised to include component repair, component replacement, performance of a more rigorous analysis, performance of an ASME Code, Section XI, Appendix A or L flaw-tolerance analysis, or scope expansion that considers other locations with the highest expected CUF_{en} values, as corrective action considerations when a cycle counting surveillance limit is exceeded. 3. Procedure(s) will be revised to require that when a cycle-counting surveillance limit is reached, action will be taken to ensure that the analytical bases of the high-energy line break (HELB) locations are maintained.	B3.1	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
47	*Neutron Fluence Monitoring* program	The *Neutron Fluence Monitoring* program is an existing condition monitoring program that is credited.	B3.2	Ongoing
48	*Environmental Qualification of Electric Equipment* program	The *Environmental Qualification of Electric Equipment* program is an existing condition monitoring program that is credited.	B3.3	Ongoing
49	*Concrete Containment Unbonded Tendon Prestress* program	The *Concrete Containment Unbonded Tendon Prestress* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be revised to specify that the trend analyses of tendon prestress loss will include trends projected through the end of the subsequent period of extended operation. 2. Procedure(s) will be revised to specify that for each surveillance interval, the predicted lower limit, minimum required value, and trending lines will be developed for the subsequent period of extended operation as part of the regression analysis for each tendon group.	B3.4	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

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Virgil C. Summer Nuclear Station

Application for Subsequent License Renewal

Appendix B
Aging Management Programs

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Appendix B

B1 Introduction

B1.1 Overview

Subsequent license renewal (SLR) Aging Management Program (AMP) descriptions are provided in this appendix for each program that has been credited for managing the effects of aging based upon the aging management review results provided in Sections 3.1 through 3.6

In general, there are four types of AMPs:

- Prevention programs preclude aging effects from occurring.
- Mitigation programs slow the effects of aging.
- Conditioning monitoring programs inspect/examine for the presence and extent of aging.
- Performance monitoring programs test the ability of a structure or component to perform its intended function.

More than one type of AMP may be implemented for a component to ensure that aging effects are managed.

Part of the demonstration that the effects of aging are adequately managed is to evaluate credited programs and activities against certain required attributes. Each of the AMPs described in this section has 10 elements which are consistent with the attributes described in Appendix A.1, "Aging Management Review - Generic (Branch Technical Position RLSB-1)" and in Table A.1-1 "Elements of an Aging Management Program for Subsequent License Renewal" of NUREG-2192. The 10-element detail is not provided when the program is deemed to be consistent with the assumptions made in NUREG-2191. The 10-element detail is only provided when the program is plant-specific. There are no plant-specific AMPs in the Virgil C. Summer Nuclear Station (VCSNS) Subsequent License Renewal Application (SLRA).

Existing initial license renewal aging management programs and activities (AMAs) were used as a starting point for subsequent license renewal AMPs. Credit has been taken for other existing plant programs whenever an initial license renewal AMA did not exist. As such, existing programs and activities associated with a system, structure, component, or commodity grouping were reviewed to determine whether they include the necessary actions to adequately manage the effects of aging during the requested subsequent period of extended operation.

Existing plant programs were often based on a regulatory commitment or requirement, rather than aging management. Many of these existing programs required for initial license renewal included the 10-element attributes, and have been demonstrated to adequately manage the identified aging effects. If an existing program is not believed to adequately manage an identified aging effect during the subsequent period of extended operation, then the program will be enhanced as necessary as discussed further below. Occasionally, the creation of a new program has been deemed necessary for purposes of subsequent license renewal.

Included in Appendix A4, Table A4.0-1, Subsequent License Renewal Commitments, are commitments for SLR with the associated implementation schedule for when Dominion plans to complete each commitment.

B1.2 Method of Discussion

Each of the AMPs in Sections B2.1.1 through B3.3 are consistent with the assumptions in Sections X and XI of NUREG-2191, or are consistent with exceptions and/or enhancements, and contain the following:

- A Program Description summary of the overall program form and function.
- A NUREG-2191 Consistency statement about the program.
- A discussion of any exceptions to the NUREG-2191 program with a justification.
- A discussion of any enhancements or additions to ensure consistency with NUREG-2191 along with a proposed schedule for completion.
- Operating Experience information specific to the program.
- A Conclusion with a bases statement of reasonable assurance that the existing program is effective, or will be effective when implemented, if new or enhanced.

There are no plant-specific AMPs in the Virgil C. Summer Nuclear Station (VCSNS) SLRA.

B1.3 Quality Assurance Program and Administrative Controls

The Quality Assurance (QA) Program is described in Topical Report DOM-QA-1, “Dominion Energy Nuclear Facility Quality Assurance Program Description,” which implements the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” The QA Program includes the three elements of Corrective Actions, Confirmation Process, and Administrative Controls, which are applicable to the safety-related and nonsafety-related systems, structures, and components (SSCs) that are subject to aging management review. The QA Program is consistent with NUREG-2191, Appendix A, “Quality Assurance for Aging Management Programs,” and the summary in NUREG-2192, Appendix A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1).”

Generically the three elements are applicable as follows:

Corrective Actions:

Results that do not meet acceptance criteria are addressed as conditions adverse to quality or significant conditions adverse to quality under Section 16, “Corrective Action,” of the QA Program. The Corrective Action Program is implemented in accordance with the requirements of 10 CFR 50, Appendix B and Topical Report DOM-QA-1. A single program is used regardless of the safety classification of the structure or component.

Corrective actions are implemented through the initiation of a Condition Report (CR) for actual or potential problems, correction of an equipment deficiency, or the need for corrective maintenance, which drive initiation of a work order. The corrective action procedures specify steps for promptly reporting, evaluating, and correcting conditions adverse to quality and significant conditions adverse to quality commensurate with the significance of the SSC or activity. Consistent with the significance of the identified condition, these steps include: (1) deficiency identification, (2) deficiency review, impact on operations and reportability determination, (3) CR review, trending and classification (including extent of condition and extent of cause), (4) corrective action determinations, assignments, and implementation, (5) assessment of effectiveness of correction, and (6) CR closure.

In the case of significant conditions adverse to quality, measures are implemented to ensure that: (a) senior station management are notified; (b) cause is determined; (c) corrective action is taken to preclude repetition; (d) the cause and corrective actions are documented and reported to station management; and (e) corrective action is taken in a timely and accurate manner.

Confirmation Process:

The Corrective Action Program contains confirmation process measures for assuring that conditions adverse to quality are promptly identified and corrected. The program stresses that verification of implementation and close-out of corrective action documentation take place and contains measures to monitor these activities by facility and oversight personnel. Station procedures include provisions for timely evaluation of adverse conditions and implementation of corrective actions required, including Root Cause Evaluations and prevention of repetition where appropriate (e.g., significant conditions adverse to quality). These procedures provide for tracking, coordinating, monitoring, reviewing, verifying, validating and approving corrective actions, and ensure that corrective actions have been effectively implemented. The corrective action process is also monitored for potentially adverse trends. Identification of a potentially adverse trend due to recurring or repetitive unacceptable conditions will result in the initiation of a CR. Since the same 10 CFR 50, Appendix B corrective actions and confirmation process are applied for nonconforming safety-related and nonsafety-related structures and components subject to aging management review for subsequent license renewal, the confirmation process is consistent with the NUREG-2191 elements.

Administrative Controls:

Information on the organizational structure, responsibilities, authorities, and personnel qualification requirements is provided in the Final Safety Analysis Report (FSAR) and in the QA Program. The organizational structure, responsibilities, authorities, and personnel qualification requirements conform to 10 CFR 50, Appendix B. The QA Program provides orderly and uniform administrative and managerial controls for safe operation of its nuclear stations. Administrative controls apply to applicable activities, documents, procedures, and instructions regardless of the safety classification of the associated system, structure, component, or commodity group. Document control processes are implemented in accordance with the requirements of 10 CFR 50, Appendix B, and implementation is further clarified in the QA Program. Measures are provided to assure that documents, including revisions or changes, are properly reviewed by independent personnel, approved, and distributed prior to use; this includes those for the activities performed under the programs credited for aging management. Administrative controls also provide for formal review and approval of corrective actions. The administrative controls apply to both safety-related and nonsafety-related SSCs which are subject to aging management.

B1.4 Operating Experience

Operating experience from internal (also referred to as “plant-specific”) and external (also referred to as “industry”) sources is captured and systematically reviewed on an ongoing basis in accordance with the QA Program, which meets the requirements of 10 CFR 50, Appendix B, and with the Operating Experience (OE) Program, which meets the requirements of NUREG-0737, “Clarification of TMI Action Plan Requirements,” Item I.C.5, “Procedures for Feedback of Operating Experience to Plant Staff.” The OE Program at Dominion interfaces with and relies on active participation in the Institute of Nuclear Power Operations (INPO) OE program, as endorsed by the NRC.

Operating experience is used to enhance plant programs, prevent repeat events, and prevent events that are similar to those that have occurred at other plants. Plant staff receive OE (internal and external) daily. The OE process includes screening, evaluation, and acting on operating experience documents and information to prevent or mitigate the consequences of similar events. External OE includes INPO documents, NRC documents (e.g., NUREG-2191 revisions, Information Notices, Regulatory Issues Summaries, and license renewal Interim Staff Guidance documents), and other industry documents (e.g., Licensee Event Reports and 10 CFR Part 21 reports, as well as relevant research and development information). Internal OE includes relevant items from the Corrective Action Program. Program health reports and program assessments are also reviewed by program owners, as applicable.

The systematic review of plant-specific and industry OE concerning aging management and age-related degradation ensures that the license renewal AMPs are, and will continue to be, effective in managing the aging effects for which they are credited. OE involving age-related degradation is tracked and trended such that adverse trends are entered into the Corrective Action Program for evaluation. Potential aging issues associated with SSCs within the scope of license renewal are evaluated with regard to: (a) materials of construction, (b) operating environment, (c) aging effects, (d) aging mechanisms, and (e) AMPs, to determine if changes to AMPs or new AMPs are needed. Existing AMPs are enhanced, or new AMPs are developed, when it is determined through the evaluation of OE that the effects of aging may not be adequately managed. Aging management programs are informed by the review of OE on an ongoing basis, regardless of the AMPs implementation schedule. Guidelines have been established for reporting plant-specific OE regarding age-related degradation and aging management to the industry through INPO, consistent with the guidance in NEI 14-13, “Use of Industry Operating Experience for Age-Related Degradation and Aging Management Programs.” The objective of reporting OE is to provide useful information to the industry in a timely manner and, therefore, support the prevention of similar events and the detection of adverse and emerging trends. In addition, the Dominion process requires the periodic conduct of AMP effectiveness reviews, such that they are performed within a five-year period and are performed consistent with the guidance of NEI 14-12, “Aging Management Program Effectiveness.”

Training on age-related degradation and aging management is 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 OE. The scope of training is linked to the responsibilities for processing OE. This training occurs on a periodic basis and includes provisions to accommodate the turnover of plant personnel.

Each AMP summary in this appendix contains examples of OE relevant to the program. This information is obtained through the review of plant-specific OE captured by the Corrective Action Program, program assessments, and program health reports, as well as the review of industry OE. New programs utilized plant-specific and/or industry OE, as applicable, and the AMP summaries in this appendix discuss the OE and associated corrective actions as they relate to implementing the new program. The OE summary for each AMP in this appendix identifies past corrective actions which have resulted in program enhancements and provides objective evidence that the effects of aging have been, and will continue to be, adequately managed so that the intended functions of the structures and components within the scope of each program will be adequately maintained during the subsequent period of extended operation.

B1.5 NUREG-2191 AMP Correlation

The correlation between NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," programs and the programs that have been credited for managing the effects of aging in the SLRA are shown in Table B1-1. For the programs, links to the sections that include the program descriptions are provided.

Table B1-1
Correlation: NUREG-2191 Program with VCSNS Program

NUREG-2191 Number	NUREG-2191 Program	Virgil C. Summer Power Station Program	Appendix B Reference
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B2.1.1
XI.M2	Water Chemistry (Primary and Secondary)	Water Chemistry (Primary and Secondary)	B2.1.2
XI.M3	Reactor Head Closure Stud Bolting (addressed by ISI program)	Reactor Head Closure Stud Bolting (addressed by ISI program)	B2.1.3
XI.M4	BWR Vessel ID Attachment Welds	Not Applicable to a PWR	N/A
XI.M7	BWR Stress Corrosion Cracking	Not Applicable to a PWR	N/A
XI.M8	BWR Penetrations	Not Applicable to a PWR	N/A
XI.M9	BWR Vessel Internals	Not Applicable to a PWR	N/A
XI.M10	Boric Acid Corrosion	Boric Acid Corrosion	B2.1.4
XI.M11B	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	B2.1.5
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	B2.1.6
XI.M16A	PWR Vessel Internals	PWR Vessel Internals	B2.1.7
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion	B2.1.8
XI.M18	Bolting Integrity	Bolting Integrity	B2.1.9

Table B1-1
Correlation: NUREG-2191 Program with VCSNS Program

NUREG-2191 Number	NUREG-2191 Program	Virgil C. Summer Power Station Program	Appendix B Reference
XI.M19	Steam Generators	Steam Generators	B2.1.10
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System	B2.1.11
XI.M21A	Closed Treated Water Systems	Closed Treated Water Systems	B2.1.12
XI.M22	Boraflex Monitoring	Not applicable. This material is not used in the VCSNS spent fuel pool racks	N/A
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B2.1.13
XI.M24	Compressed Air Monitoring	Compressed Air Monitoring	B2.1.14
XI.M25	BWR Reactor Water Cleanup System	Not Applicable to a PWR	N/A
XI.M26	Fire Protection	Fire Protection	B2.1.15
XI.M27	Fire Water System	Fire Water System	B2.1.16
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks	Outdoor and Large Atmospheric Metallic Storage Tanks	B2.1.17
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry	B2.1.18
XI.M31	Reactor Vessel Material Surveillance	Reactor Vessel Material Surveillance	B2.1.19
XI.M32	One-Time Inspection	One-Time Inspection	B2.1.20
XI.M33	Selective Leaching	Selective Leaching	B2.1.21
XI.M35	ASME Code Class 1 Small-Bore Piping	ASME Code Class 1 Small-Bore Piping	B2.1.22
XI.M36	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components	B2.1.23
XI.M37	Flux Thimble Tube Inspection	Flux Thimble Tube Inspection	B2.1.24

Table B1-1
Correlation: NUREG-2191 Program with VCSNS Program

NUREG-2191 Number	NUREG-2191 Program	Virgil C. Summer Power Station Program	Appendix B Reference
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B2.1.25
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis	B2.1.26
XI.M40	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	B2.1.27
XI.M41	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks	B2.1.28
XI.M42	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B2.1.29
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE	B2.1.30
XI.S2	ASME Section XI, Subsection IWL	ASME Section XI, Subsection IWL	B2.1.31
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF	B2.1.32
XI.S4	10 CFR Part 50, Appendix J	10 CFR Part 50, Appendix J	B2.1.33
XI.S5	Masonry Walls	Masonry Walls	B2.1.34
XI.S6	Structures Monitoring	Structures Monitoring	B2.1.35
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants	B2.1.36
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance	B2.1.37
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.38

Table B1-1
Correlation: NUREG-2191 Program with VCSNS Program

NUREG-2191 Number	NUREG-2191 Program	Virgil C. Summer Power Station Program	Appendix B Reference
XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	B2.1.39
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.40
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.41
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.42
XI.E4	Metal-Enclosed Bus	N/A	N/A
XI.E5	Fuse Holders	Fuse Holders	B2.1.43
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.44
XI.E7	High-Voltage Insulators	High-Voltage Insulators	B2.1.45
X.M1	Fatigue Monitoring	Fatigue Monitoring	B3.1
X.M2	Neutron Fluence Monitoring	Neutron Fluence Monitoring	B3.2
X.E1	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment	B3.3
X.S1	Concrete Containment Unbonded Tendon Prestress	Concrete Containment Unbonded Tendon Prestress	B3.4

B1.6 Time-Limited Aging Analysis Programs

The following time-limited aging analysis aging management programs are described in the sections listed in this appendix. These programs are discussed in NUREG-2191, Chapter X.

- Fatigue Monitoring (Section B3.1)
- Neutron Fluence Monitoring (Section B3.2)
- Environmental Qualification of Electric Equipment (Section B3.3)
- Concrete Containment Unbonded Tendon Prestress (Section B3.4)

B2 Aging Management Programs

Table B2-1 lists the aging management programs described in this appendix and identifies the programs consistency with the corresponding NUREG-2191 program. As discussed in Section B1.4, both plant-specific and industry operating experience has been reviewed and considered as it relates to both new and existing aging management programs.

Table B2-1
VCSNS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New VCSNS Program	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B2.1.1	Existing	X	
Water Chemistry (Primary and Secondary)	B2.1.2	Existing		
Reactor Head Closure Stud Bolting (addressed by ISI program)	B2.1.3	Existing	X	X
Boric Acid Corrosion	B2.1.4	Existing		
Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components	B2.1.5	Existing		
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	B2.1.6	Existing		
PWR Vessel Internals	B2.1.7	Existing	X	
Flow-Accelerated Corrosion	B2.1.8	Existing		
Bolting Integrity	B2.1.9	Existing	X	
Steam Generators	B2.1.10	Existing		
Open-Cycle Cooling Water System	B2.1.11	Existing	X	
Closed Treated Water Systems	B2.1.12	Existing	X	

Table B2-1
VCSNS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New VCSNS Program	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B2.1.13	Existing	X	
Compressed Air Monitoring	B2.1.14	Existing	X	
Fire Protection	B2.1.15	Existing	X	
Fire Water System	B2.1.16	Existing	X	
Outdoor and Large Atmospheric Metallic Storage Tanks	B2.1.17	New		
Fuel Oil Chemistry	B2.1.18	Existing	X	
Reactor Vessel Material Surveillance	B2.1.19	Existing		
One-Time Inspection	B2.1.20	New		
Selective Leaching	B2.1.21	New		
ASME Code Class 1 Small-Bore Piping	B2.1.22	Existing	X	
External Surfaces Monitoring of Mechanical Components	B2.1.23	Existing	X	
Flux Thimble Tube Inspection	B2.1.24	Existing		
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B2.1.25	Existing	X	
Lubricating Oil Analysis	B2.1.26	Existing	X	
Monitoring of Neutron-Absorbing Materials Other Than Boraflex	B2.1.27	Existing		
Buried and Underground Piping and Tanks	B2.1.28	Existing	X	

Table B2-1
VCSNS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New VCSNS Program	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B2.1.29	New		
ASME Section XI, Subsection IWE	B2.1.30	Existing	X	
ASME Section XI, Subsection IWL	B2.1.31	Existing		
ASME Section XI, Subsection IWF	B2.1.32	Existing	X	X
10 CFR Part 50, Appendix J	B2.1.33	Existing		
Masonry Walls	B2.1.34	Existing	X	
Structures Monitoring	B2.1.35	Existing	X	
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B2.1.36	Existing	X	
Protective Coating Monitoring and Maintenance	B2.1.37	Existing		
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.38	Existing	X	
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	B2.1.39	Existing		
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.40	Existing	X	

Table B2-1
VCSNS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New VCSNS Program	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.41	New		
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.42	New		
Fuse Holders	B2.1.43	New		
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.44	New		
High-Voltage Insulators	B2.1.45	New		
Fatigue Monitoring	B3.1	Existing	X	
Neutron Fluence Monitoring	B3.2	Existing		X
Environmental Qualification of Electric Equipment	B3.3	Existing		
Concrete Containment Unbonded Tendon Prestress	B3.4	Existing	X	X

B2.1 NUREG-2191 Chapter XI Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter XI programs credited for managing the effects of aging.

B2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is an existing condition monitoring program that manages cracking and loss of material. The program consists of periodic volumetric, surface, and/or visual examination, and leakage tests of the ASME Code, Section XI, Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, identification of degradation, and establishment of corrective actions.

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program implements the required component examination schedule in accordance with ASME Code, Section XI, Subsections IWB-2400, IWC-2400 or IWD-2400 and examination categories, applicable components, examination methods, acceptance standards, and frequency of examination as specified in ASME Code, Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 for Class 1, 2, and 3 components, respectively. The examination methods specified in ASME Code, Section XI Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 are based on approved industry standards for detecting age-related degradation of components. The program requires that indications and relevant conditions detected during examinations be evaluated in accordance with ASME Code, Section XI, Articles IWB-3000 for Class 1, IWC-3000 for Class 2, and IWD-3000 for Class 3. The program directs that repair and replacement activities be performed in accordance with ASME Code, Section XI, Article IWA-4000.

Additional examinations not required by the ASME Code, Section XI, but using ASME Code, Section XI, inspection techniques and acceptance criteria, are performed in accordance with the augmented inspection activities which are included in the ISI Program Plan. Augmented examinations include the following requirements:

- Additional examinations for pressure-retaining welds in Class 1 components fabricated with Alloy 600/82/182 materials (Code Case N-722 as incorporated by reference in 10 CFR 50.55a).
- Alternative examinations for the reactor upper head with nozzles having pressure-retaining partial-penetration welds (Code Case N-729 as incorporated by reference in 10 CFR 50.55a).

- Alternative examination requirements and acceptance standards for the following Class 1 piping and vessel nozzle butt welds fabricated with UNS N06082 or UNS W86182 weld filler material (Code Case N-770 as incorporated by reference in 10 CFR 50.55a).
    - Pressurizer nozzle welds
    - Reactor vessel 'B' hot leg welds
    - Reactor vessel 'C' hot leg welds
    - Reactor vessel cold leg welds
    - Steam generator inlet (hot leg) welds
    - Steam generator outlet (cold leg) welds
- Examinations and evaluations of PWR vessel internals (MRP-227).
- Management of thermal fatigue in normally stagnant non-isolable RCS branch lines (MRP-146/MRP-146S. Implemented under NEI 03-08).
- Assessment of RHR Mixing Tee Thermal Fatigue (MRP-192. Implemented under NEI 03-08).

During the fourth inservice inspection interval (January 1, 2014 through December 31, 2023), inservice inspections are performed consistent with ASME Code, Section XI, 2007 Edition through 2008 Addenda, as incorporated in 10 CFR 50.55a. In conformance with 10 CFR 50.55a(g)(4)(ii), the Inservice Inspection program is updated during each successive 120-month inspection interval to comply with the requirements of the edition of the Code that is applicable 18 months before the start of the inspection interval. ASME Code, Section XI, editions and addenda will be used consistent with the provisions of 10 CFR 50.55a during the subsequent period of extended operation. Any deviation from ASME Code, Section XI, requirements must be approved by the NRC per a relief request or alternate request.

A Risk-Informed Inservice Inspection (RI-ISI) program has been developed using the methodology described in EPRI Topical Report TR-112657, Rev B-A, “Revised Risk-Informed Inservice Inspection Evaluation Procedure”. Implementation of the RI-ISI program is consistent with ASME Code, Section XI, Code Case N-716-1, “Alternative Classification and Examination Requirements, Section XI, Division 1”. Note: The basis for the RI-ISI program is anticipated to be updated to Code Case N-716-2 for the fifth inspection interval. The implementation of a RI-ISI program was permitted by NRC approval of Relief Request RR-4-13 for the use of a risk-informed process as an alternative for component selections. The inspection categories for the RI-ISI program are:

- B-F, Pressure-retaining dissimilar metal welds in vessel nozzles
- B-J, Pressure-retaining welds in piping
- C-F-1, Pressure-retaining welds in austenitic stainless steel or high alloy piping
- C-F-2, Pressure-retaining welds in carbon or low-alloy piping

The RI-ISI program has been incorporated into the ISI Program Plan.

A flaw tolerance evaluation was performed for welds associated with sentinel locations assessed under ASME Code, Section XI, Appendix L. The sentinel locations to be examined periodically include auxiliary lines for the following:

- Normal charging and alternate charging (3-inch diameter RCS cold leg nozzle)
- Surge (14-inch hot leg surge nozzle; nozzle-to-pipe weld)

A flaw tolerance evaluation was performed for the reactor vessel shell welds associated with sentinel locations assessed under ASME Code, Section XI, Appendix A. The sentinel locations to be examined periodically include the reactor vessel shell-to-outlet nozzle welds.

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program includes the component inspection activities required by ASME Code, Section XI, Subsections IWB, IWC, and IWD, except for those components that are covered by the following programs:

- *Reactor Head Closure Stud Bolting* program (B2.1.3)
- *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program (B2.1.5)
- *PWR Vessel Internals* program (B2.1.7)
- *Bolting Integrity* program (B2.1.9)
- *Steam Generators* program (B2.1.10)
- *ASME Code Class 1 Small-Bore Piping* program (B2.1.22)
- *Flux Thimble Tube Inspection* program (B2.1.24)
- *ASME Section XI, Subsection IWF* program (B2.1.32)
- *Fatigue Monitoring* program (B3.1)

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD.”

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedures will be revised to require volumetric inspection of the pressurizer surge line hot leg nozzle every 48 years for management of EAF. Based on satisfactory results from the last inspection performed in Q2 1993, the next inspection will be performed by Q2 2041.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2012, UT indications were identified on four control rod drive mechanism (CRDM) penetrations during performance of volumetric examinations of the reactor vessel (RV) closure head. These examinations were performed in accordance with ASME Boiler & Pressure Vessel (BPV) Code Case N-729-1. One vent line penetration and 65 CRDM penetrations were included in the penetration inspections performed during the refueling outage. Repairs were performed on four CRDM penetration nozzles and associated J-groove welds using the Westinghouse Embedded Flaw Repair process in accordance with NRC-approved WCAP-15987 (ADAMS Accession No. ML031840237). PWSCC was identified as the apparent cause of the flaws. Corrective actions included repairing the penetrations and revising the frequency of the bare metal visual exam and the volumetric exam to every refueling outage.
2. In April 2014, during the Spring refueling outage, volumetric inspections of the 66 RV closure head penetrations (65 CRDM and one RV closure head vent system line) identified five reactor CRDM penetrations that did not meet the requirements of 10 CFR 50.55a(g)(b)(ii)(D) and American Society of Mechanical Engineers (ASME) Section XI Code Case N-729-1. The indications were not through-wall as confirmed by volumetric and bare metal visuals. The flaws were repaired using the embedded flaw repair process in accordance with NRC-approved WCAP-15987. The apparent cause of the flaws was attributed to primary water stress corrosion cracking. The replacement RV closure head that was installed during the Spring

2017 refueling outage uses PWSCC-resistant Alloy 690 piping material and Alloy 52 welding material.

3. In August 2015, the examination coverage was less than the 90% ASME Code requirement for four Class 1 welds and two Class 2 welds due to obstructions. Notification to the NRC was provided in relief request RR-III-12 for the inability to achieve at least 90% coverage. Approval of the relief request was provided in a Safety Evaluation Report dated July 1, 2016 (ADAMS Accession No. ML16161A045). No further action was required. The ISI database was updated to note the limited coverage.
4. In August 2019, an industry event involving reactor vessel head nozzle penetration flaw indications was reviewed for ISI Program impact; no required actions were identified. The event for an inner diameter-initiated flaw on a reactor vessel head penetration nozzle was mis-characterized by the vendor and eventually resulted in a through-wall crack as evidenced by boric acid leakage. Re-evaluation of ultrasonic test data confirmed an inner diameter-initiated axial flaw characteristic of primary water stress corrosion cracking (PWSCC). PWSCC in Alloy 600 materials is recognized as a significant issue in PWR reactor coolant systems. During the Spring 2017 refueling outage, the reactor vessel head was replaced as a means of addressing PWSCC concerns with Alloy 600 materials. The replacement head is a one-piece forging with penetration nozzles fabricated from Alloy 690 material and Alloy 52 welding material. These materials are considered PWSCC resistant.

The above examples of operating experience provide objective evidence that the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program includes activities to perform periodic volumetric, surface, and/or visual examinations, and leakage tests to identify cracking and loss of material for the ASME Code, Section XI, Class 1, 2, and 3 pressure-retaining components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.2 Water Chemistry

Program Description

The *Water Chemistry* program is an existing preventive program that manages cracking, loss of material, reduction of heat transfer, and wall thinning of components exposed to a reactor coolant, steam, treated borated water, and treated water environment. The scope of the Primary *Water Chemistry* program includes monitoring and control of the chemical environment in the reactor coolant system and related pressurized water reactor interfacing systems. The scope of the Secondary *Water Chemistry* program includes monitoring and control of the chemical environment in the steam generator secondary side and the secondary cycle systems. The Primary *Water Chemistry* program is consistent with EPRI Report 3002000505, Revision 7 (April 2014), “Pressurized Water Reactor Primary Water Chemistry Guidelines.” The Secondary *Water Chemistry* program is consistent with EPRI Report 3002010645, Revision 8 (September 2017), “Pressurized Water Reactor Secondary Water Chemistry Guidelines.”

The primary and secondary water chemistry control strategies are set forth in strategic plans and implemented by procedures. The programmatic control of the chemical environment ensures that the aging effects due to contaminants are limited. The methods used to manage both the primary and secondary chemical environments rely on the principles of: (1) limiting the concentration of chemical species known to cause corrosion and (2) addition of chemical species known to inhibit material degradation by their influence on pH and dissolved oxygen levels.

The primary portion of the program is consistent with EPRI Report 3002000505 and includes specific limits for pH, lithium, fluoride, chloride, sulfate, dissolved oxygen, and other parameters. Control of reactor coolant and related interfacing system contaminants is maintained by using micron and submicron filters and mixed bed demineralizers, which provide mechanical filtration and ion exchange functions to remove contaminants. Lithium hydroxide addition is used to control reactor coolant pH, while hydrogen addition is utilized for oxygen scavenging.

The secondary portion of the program is consistent with EPRI Report 3002010645 and includes specific limits for chloride, sulfate, sodium, hydrazine, dissolved oxygen, total iron, pH, conductivity, and other parameters. Chemical control of the secondary systems is established and maintained by removing contaminants with steam generator blowdown combined with condensate demineralizers during startup and mechanical filtration during power operations. Chemical addition of approved amines (e.g.: methoxypropylamine-MPA), is utilized for pH control. Carbohydrazide (CHZ) and hydrazine are used to scavenge oxygen in secondary systems.

Water chemistry control is generally effective in areas of intermediate and high flow where mixing takes place and the monitoring samples are representative of actual conditions. For low-flow areas and stagnant portions of the systems, sampling may not be as effective in determining local chemical environment conditions. A one-time inspection prior to the period of subsequent license renewal of a representative group of components provides verification of the effectiveness of the *Water Chemistry* program in these low-flow areas. This inspection will be performed as part of the *One-Time Inspection* program (B2.1.20) for the verification of the effectiveness of the *Water Chemistry* program.

The *Water Chemistry* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Water Chemistry* program is an existing program that is consistent with NUREG-2191, Section XI.M2, “Water Chemistry,” as modified by SLR-ISG-2021-02-MECHANICAL, "Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance."

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Water Chemistry* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2015, during the feedwater booster pump sample for weekly integrated iron and copper, the iron analysis was out of specification high at 6.1 ppb (limit is 5.0 ppb). During the sample collection period, a transient occurred in the plant, with a high pressure heater string being returned to service and a power level increase from 80 to 100%. Transients such as these can result in the release of corrosion products from components and piping in the feedwater system. The sample collected during the following week returned to within normal limits at 1.5 ppb and the subsequent weekly sample collected was 1.17 ppb.

   Benchmarking was subsequently conducted with another plant to determine if there were practices that could be shared to reduce iron transport issues. The benchmarking did not identify any new practices or process improvements which would benefit VCSNS.

2. In February 2015, a 55-gallon drum of Methoxypropylamine (MPA) was mistakenly used instead of Carbohydrazide (CHZ) to batch the condensate hydrazine injection tank. This caused feedwater hydrazine concentration to decrease below the expected value, and steam generator and feedwater MPA concentrations to exceed expected values.

   Methoxypropylamine is a chemical that is normally added to the condensate system but was placed in the incorrect batching tank, which resulted in an elevated MPA concentration due to over feeding. The MPA concentration was restored to normal and improvements in procedures, processes and training have been implemented to prevent future incidents. No other instances of improper batching have been identified.

3. In May 2016, after a cation bed was placed in service to de-lithiate the reactor coolant system (RCS), a sample was obtained and the results were as expected. When the RCS was sampled again several hours later with the cation bed out of service, the lithium concentration had slightly decreased and, since a Quality Control (QC) check had verified that the instrument used in the measurement was performing correctly, the chemist suspected that the cation bed was not fully secured. Operations was notified of the issue and the cation bed was inspected to ensure flow was secured. Once the cation bed was verified to be isolated with no flow, the analytical columns in the instrument were inspected and replaced. After equilibration and calibration, the instrument was placed back in service. QC results were satisfactory and lithium values had returned to expected concentrations. The age of the analytical columns in the instrument, along with excess loading of sodium, had contributed to column failures, which in turn contributed to lower lithium concentration values. It was concluded that lithium concentration in the RCS was never out of specification. This was further verified during the troubleshooting process when another analytical method known as atomic absorption was used to determine lithium concentration.

4. In April 2017, a steadily increasing trend in chloride concentration in the three steam generators (SGs) was identified, which in a three-day period went from 0.8 ppb to 10 ppb, with the expected value being 3 ppb. On the fourth day, chlorides in 'A',' B', and 'C' SGs were at 14.96 ppb, 14.11 ppb, and 15.92 ppb, respectively (Action Level 1). Troubleshooting to determine the source of chloride was performed involving systematic evaluation of multiple potential sources. The temporary use of a vendor supplied trailer to produce filtered water was subsequently confirmed to be the source for contaminated ingress of organic chlorides. Actions taken to restore parameters to acceptable standards included increasing blowdown to manage contaminant levels and adjusting chemical feed rates to the filtered water trailer. No secondary Technical Specification values were exceeded and the SGs remained operable. Procedure guidance was added to consider organic contaminant sources when evaluating abnormal SG results for chloride and sulfate.

5. In November 2018 (RF24), during plant start up at the 30% power chemistry hold, chemistry analysis results indicated that a cleanup rate for sodium in the SGs could not be established. The steam generator blowdown and condensate polishing systems were in service and the chloride and sulfate concentrations were decreasing at the expected cleanup rate. The condensate polishing system was then removed from service and monitoring of the SG chemistry was continued. Chemistry results showed the expected cleanup rate was obtained after the condensate polishing system was removed from service.

   Investigation and operating experience from Spring 2017 (RF23) indicated that the condensate polishing resin in use was possibly throwing sodium at below detectable levels and was concentrating in the SGs. The reason a cleanup rate for sodium in the SGs could not be established during the RF24 30% power chemistry hold was attributed to ineffective condensate polishing resin allowing sodium to be passed through or expelled from the condensate polishers. To promote better sodium removal, changes to the condensate polishing system procedure were made to modify the resin loading process if resin throw was indicated.

The above examples of operating experience provide objective evidence that the *Water Chemistry* program includes activities to control chemistry parameters in treated water environments to manage cracking, loss of material, reduction of heat transfer, and wall thinning of components exposed to a reactor coolant, steam, treated borated water, and treated water environments within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Water Chemistry* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Water Chemistry* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Water Chemistry* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.3 Reactor Head Closure Stud Bolting

Program Description

The *Reactor Head Closure Stud Bolting* program is an existing condition monitoring program that manages cracking and loss of material of the reactor head closure stud assembly (closure studs, washers, and nuts) and for the threads in the reactor vessel flange.

The *Reactor Head Closure Stud Bolting* program is implemented as part of the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1). The program is consistent with the examination and inspection requirements specified in ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, Category B-G-1. The current Inservice Inspection (ISI) Program for the fourth 10-year inspection interval is based on the ASME Code, Section XI, 2007 Edition through 2008 Addenda. Future 120-month inspection intervals will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a 18 months before the start of the ISI inspection interval. The *Reactor Head Closure Stud Bolting* program includes preventive measures to address reactor head closure stud bolting degradation consistent with those identified in NRC Regulatory Guide (RG) 1.65, Revision 1, “Material and Inspection for Reactor Vessel Closure Studs.”

The *Reactor Head Closure Stud Bolting* program uses visual and volumetric examinations in accordance with the general requirements of ASME Code, Section XI, Article IWA-2000. The closure studs and threads in the reactor vessel flange receive a volumetric examination, and the surfaces of washers, and nuts at the reactor vessel flange are inspected using a visual examination (VT-1). Pressure boundary retaining components in examination category B-P receive a visual examination (VT-2) during system leakage tests and system hydrostatic tests.

Preventive measures for the *Reactor Head Closure Stud Bolting* program include the following attributes:

- No metal plating is used on the studs.
- Phosphated surface treatment is used on the studs.
- Neolube® is used to lubricate the studs (precluding the use of molybdenum sulfides).

The material used for the reactor head closure studs, washers, and nuts (and spares) is ASTM SA-540, Grade B24, Class 3. The procurement documents for the closure studs did not require the material to have a measured yield strength value of less than 150 ksi or an ultimate tensile strength value of less than 170 ksi. This includes three spare reactor head closure studs which have not as yet been installed. As a result, the installed studs present a potential concern for stress corrosion cracking (SCC) based on the limits stipulated in RG 1.65, Revision 1.

To address the potential for SCC for the reactor head closure studs that are being used, ultrasonic examinations are performed during each ASME Code, Section XI, inspection interval. For the three spare studs that have strength values that could exceed the RG 1.65, Revision 1 limits of 150 and 170 ksi, the potential for SCC will not be a concern unless those spares were to be placed into service. At that time, the potential for SCC will be addressed by the ultrasonic examinations which continue to be performed in accordance with ASME Code, Section XI.

Any indication of degradation in reactor head closure stud bolting is evaluated in accordance with ASME Code, Section XI, Subsection IWB-3100, by comparing ISI results with the acceptance standards of ASME Code, Section XI, Subsections IWB-3400 and IWB-3500.

The *Reactor Head Closure Stud Bolting* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Reactor Head Closure Stud Bolting* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M3, “Reactor Head Closure Stud Bolting.”

Exception Summary

The following program element(s) are affected:

Preventive Actions (Element 2) and Corrective Actions (Element 7)

1. NUREG-2191 indicates in Section XI.M3, Reactor Head Closure Stud Bolting, that the program relies on the recommendations of RG 1.65, Revision 1, April 2010. RG 1.65, Revision 1 recommends that actual measured yield strength should not exceed 150 ksi for newly installed studs or 170 ksi ultimate tensile strength for existing studs. The installed and spare reactor head closure studs were not procured under specifications that limited the measured maximum yield and ultimate tensile strengths, which presents a concern for SCC. Therefore, the program takes exception to the recommendation that measured yield strength should not exceed 150 ksi for newly installed studs or 170 ksi ultimate tensile strength for existing studs.

Justification for Exception

Cracking has been identified as an aging effect requiring management for the reactor head closure studs. The volumetric examination method in place for stud inspection per ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 is appropriate to identify cracking. There have been no recordable cracking indications identified by ISI program examinations of reactor head closure bolting components, indicating that the current program has been effective to manage cracking. The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) will continue to include volumetric examination per ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1, and therefore will continue to be effective in managing cracking during the subsequent period of extended operation for existing studs and for spare studs upon installation.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement will be implemented in the following program element(s):

Preventive Actions (Element 2) and Corrective Actions (Element 7)

1. Procurement documents for reactor head closure studs will be revised to incorporate guidance from RG 1.65, Revision 1 and NUREG-2191, Section XI.M3, to add a limit for the maximum measured yield strength of 150 ksi and a limit for maximum tensile strength of 170 ksi.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Reactor Head Closure Stud Bolting* program has been, and will be effective in managing the aging effects for systems, structures, and components within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2012 during closure head studs ultrasonic testing, debris was found in the studs. An analysis had been performed on similar material found in the hydranuts and on material identified during the visual of the reactor vessel (RV) flange ligament. Chemical analysis was performed on the hardened material found in the studs and on a clean sample of the hydranut oil used hydraulically to stretch the RV studs during tensioning. The analysis concluded that the hardened material was old, decomposed hydranut oil lubricant that had leaked onto the equipment during past tensioning efforts and had baked on due to elevated temperatures during plant operation.

   The hydranuts were inspected and refurbished as applicable prior to use in tensioning the RV studs. The oil was cleaned from the RV studs and flange area. Prior to closure of the RV closure head, VT-1 examinations were performed on the hydranuts and washers, and ultrasonic examinations were performed on the RV studs and RV flange threads. As a result, no signs of degradation were identified.

2. In November 2015 (RF22), the RV closure head hydranuts were removed and were replaced with conventional nuts and washers similar to those originally installed. The hydranuts had not performed as desired during their service life, including repeated leaks of hydraulic oil, which formed a basis for the replacement decision. An evaluation concluded the replacement closure

nuts and washers were equal to or better than the original design closure nuts and washers, and were acceptable for use on the RV closure head. No degradation was identified during the pre-installation inspection of the RV studs and the new nuts and washers, and the replacement effort was successfully completed.

The above examples of operating experience provide objective evidence that the *Reactor Head Closure Stud Bolting* program includes activities to perform volumetric and visual inspections to manage cracking and loss of material of the reactor head closure stud assembly (closure studs, washers, nuts, and the threads in the reactor vessel flange) within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Reactor Head Closure Stud Bolting* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Reactor Head Closure Stud Bolting* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Reactor Head Closure Stud Bolting* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.4 Boric Acid Corrosion

Program Description

The *Boric Acid Corrosion* program is an existing condition monitoring program that manages loss of material due to leaking borated water on structures and components (including electrical equipment/junction boxes) within the scope of subsequent license renewal that are susceptible to boric acid corrosion. The program includes provisions to identify leakage through inspection and examination. When leakage is identified, a visual inspection is performed that identifies the leakage pathway and any boric acid residue on adjacent structures, components, and supports so that leakage clean-up can begin, and corrective actions can be initiated, as necessary. When it is determined that an evaluation is necessary, it is performed in a timely manner. Follow-up inspections may be performed to ensure that the corrective actions were adequate and addressed the identified age-related degradation.

The *Boric Acid Corrosion* program relies in part on NRC Generic Letter 88-05 (GL 88-05), “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,” for guidance to identify, evaluate, and correct borated water leaks that could cause corrosion damage to reactor coolant pressure boundary components. Borated water leakage from components outside the scope of the program established in response to GL 88-05 may affect components within the scope of subsequent license renewal. Therefore, this program includes components within the scope of subsequent license renewal exposed to an air environment with borated water leakage that are susceptible to boric acid corrosion.

The *Boric Acid Corrosion* program is consistent with Section 7 of WCAP-15988-NP, Revision 2, “Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors.” Additionally, the program includes examinations conducted during Inservice Inspection (ISI) pressure tests performed in accordance with ASME Code, Section XI requirements. Specific attributes from WCAP-15988-NP are addressed in implementing procedures.

The *Boric Acid Corrosion* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Boric Acid Corrosion* program is an existing program that is consistent with NUREG-2191, Section XI.M10, “Boric Acid Corrosion.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Boric Acid Corrosion* program has been, and will be effective in managing the aging effects for systems, structures, and components within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In September 2011, during a Reactor Building entry, boric acid leakage was observed coming from a coupling located between the instrument valve and its downstream pipe cap in the low side test connection piping for the 'A' reactor coolant loop hot leg flow element. The leakage was classified as active, non-minor, discolored, and with multiple targets. The leakage was dripping constantly at an estimated leakrate of 0.05 gpm and was affecting valves and other surfaces below. Corrosion was noted on two of the valves and the Reactor Building steel liner. The cause for the leakage was identified as seat leakage from the instrument valve.

   The test connection coupling fittings were tightened, the pipe cap was replaced, and no leakage from the piping was verified. The residue was cleaned, visual examination technique (VT) inspections were performed on affected surfaces, and no excessive corrosion was found. To eliminate the seat leakage condition, the low side test connection instrument valve was replaced during Spring 2014 (RF21).

2. In October 2012, an active boric acid leak was found on the alternate seal injection pump. The leakage was coming from the pump plunger drains tubing through a stainless steel (SS) fitting that had not been fully connected to permanent drain tubing. The leakage was classified as non-minor, discoloration was noted on the painted carbon steel skid base, and degradation of the painted carbon steel mounting bolts for the coupling guard was evident. The connection between the pump plunger drains tubing and the permanent drain tubing was completed which eliminated the leakage from the SS fitting. The boric acid residue was cleaned from the affected components and a VT inspection performed on the carbon steel mounting bolts found them to be satisfactory for use. The skid base was repainted in the corroded areas to mitigate further corrosion and paint touch-ups were done on the pump motor.

3. In March 2013, during the boric acid walk down inspection of the Reactor Building, boric acid leakage was found at the excess letdown heat exchanger. The source of the leakage could not immediately be determined due to the installed insulation. The leak was classified as active

and non-minor. Upon removal of the insulation, the leak was determined to be from the heat exchanger head gasket. The targets for the leakage were the SS insulation, the SS piping below the heat exchanger, painted carbon steel bolting, and the floor. A bolt pulled from the position with the worst corrosion degradation deposits was evaluated by Engineering and VT-1 inspected by Quality Control (QC). The degradation was identified as surface corrosion and it was determined that the bolt would still perform its design function and meet code requirements. A new bolt and two new nuts were installed in place of the bolt and two nuts which had been removed for examination. No significant wastage was found on the components in contact with the boric acid. A torque pass performed on the flanged connection stopped the gasket leak.

4. In April 2014, after cooldown and depressurization during RF21, evidence of boric acid leakage was identified by QC at the 'B' steam generator (SG) hot leg and cold leg primary manways. The leakage was determined to be from the primary manways. Boric acid was in contact with the manway covers which were constructed of SA533 GrB Class 1 alloy steel. The leakage was classified as non-active and minor, and only trace amounts of boric acid were noted. Targets were the flange and mirror insulation below each manway. The manway covers were removed to allow for eddy current testing of the 'B' SG. Following cleaning of the boric acid, a visual inspection was performed on the affected components. There were no signs of discoloration or degradation and the results were acceptable. Upon completion of the eddy current testing, the manway covers were reinstalled with new flexitallic gaskets and no boric acid leakage was observed.

The above examples of operating experience provide objective evidence that the *Boric Acid Corrosion* program includes activities to perform visual inspections to identify loss of material due to leaking borated water on structures and components (including electrical equipment/junction boxes) within the scope of subsequent license renewal that are susceptible to boric acid corrosion, and to initiate corrective actions. Occurrences identified under the *Boric Acid Corrosion* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Boric Acid Corrosion* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Boric Acid Corrosion* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

Program Description

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is an existing condition monitoring program that manages cracking due to primary water stress corrosion cracking (PWSCC) for components or welds constructed from Alloy 600/82/182 and exposed to pressurized water reactor (PWR) primary coolant at elevated temperatures. Initiation and growth of PWSCC cracks can occur as a function of variables which include, but are not limited to temperature, stress, microstructure, time, and water chemistry. This program is used in conjunction with the *Water Chemistry* program (B2.1.2).

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is patterned after the industry guidance document, MRP-126, “Materials Reliability Program: Generic Guidance for Alloy 600 Management.” Bare-metal visual, surface, and volumetric inspections are used to detect the presence of PWSCC.

Nickel alloy components for which PWSCC has been mitigated by use of a full structural weld overlay (FSWOL) of Alloy 52/152 material, including the pressurizer surge, spray, safety, and relief nozzle-to-pipe butter and welds, are inspected (ASME Code Case N-770 (Item C-1), as incorporated by reference in 10 CFR 50.55a).

Nickel alloy components for which PWSCC has been mitigated by use of the Mechanical Stress Improvement Process (MSIP™) mitigation strategy, including the reactor vessel 'B' and 'C' loop hot leg nozzle-to-pipe butter and welds, are inspected (ASME Code Case N-770 (Items D and E), as incorporated by reference in 10 CFR 50.55a).

Nickel-alloy components that are inspected due to susceptibility to PWSCC for which PWSCC has not been mitigated include the following:

- Reactor vessel bottom-mounted instrumentation (BMI) nozzles and J-groove welds (ASME Code Case N-722, as incorporated by reference in 10 CFR 50.55a).
- Reactor vessel BMI nozzle-to-pipe (guide tube) welds (inspected during performance of ASME Code Case N-722 inspections).
- Reactor vessel cold leg nozzle-to-pipe butter and welds (ASME Code Cases N-722 and N-770 (Item B-2), as incorporated by reference in 10 CFR 50.55a).
- Steam generator cold leg nozzle-to-pipe butter and welds (ASME Code Cases N-722 and N-770 (Item B-2)[Note 1], as incorporated by reference in 10 CFR 50.55a).

- Steam generator hot leg nozzle-to-pipe butter and welds (ASME Code Cases N-722 and N-770 (Item A-2)[Note 1], as incorporated by reference in 10 CFR 50.55a).

  Note 1. Although the steam generator inlet and outlet nozzles dissimilar metal welds have a PWSCC resistant Alloy 52/152 inlay material on the inside surface to provide a barrier to isolate the PWSCC susceptible Alloy 82/182 dissimilar metal weld, the inlayed material is not considered resistant by the NRC.

Nickel-alloy components that are resistant to PWSCC but are inspected include the replacement reactor vessel (RV) closure head penetration nozzles and associated J-groove welds (ASME Code Case N-729, as incorporated by reference in 10 CFR 50.55a).

There are no susceptible nickel-alloy branch line connections that would require a baseline volumetric or inner diameter surface inspection in accordance with ASME Code Case N-770, as incorporated by reference in 10 CFR 50.55a.

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program inspects components that are susceptible to loss of material due to boric acid leakage from nearby or adjacent nickel-alloy components previously described. Findings of boric acid on Alloy 600/82/182 components are documented in accordance with the *Boric Acid Corrosion* program (B2.1.4).

The *Water Chemistry* program (B2.1.2) monitors and controls water environments consistent with industry guidelines to ensure that the reactor coolant water environments are favorable to mitigate PWSCC in nickel-alloy components.

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is an existing program that is consistent with NUREG-2191, Section XI.M11B, “Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In Fall 2000 (RF12), the station discovered a crack on the reactor pressure vessel 'A' hot leg nozzle when boric acid was found on the floor of the Reactor Building. The crack was located in the dissimilar metal weld between the reactor coolant system piping and the vessel nozzle, on the nozzle side of the weld. The weld used Inconel 182 butter (safe end) between the weld piece and the vessel nozzle. The crack was the subject of NRC Information Notice 00-17 (IN 00-17), “Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer.” The investigation into the crack concluded that the cause was indirectly attributed to PWSCC. The weld at the nozzle was determined to be subjected to high tensile stresses as a result of extensive weld repairs performed during the original construction. A number of smaller PWSCC cracks were subsequently identified when the weld was cut out and destructively tested. A spool piece was used to replace the affected weld and was installed utilizing Inconel 52 and 152 weld materials, in effect removing the susceptible material. The welding was performed in a manner which minimized residual stresses. The reactor pressure vessel 'A' hot leg nozzle-to-pipe welds are in the RI-ISI program. These welds were inspected using ultrasonic inspections in Fall 2003 (RF14) and Fall 2012 (RF20) with no recordable indications identified. Further inspections of the 'B' and 'C' hot leg nozzle safe end-to-pipe welds detected minor indications of cracking.

   In a letter to the NRC dated January 9, 2001 (ADAMS Accession No. ML010180271), a commitment was made to perform, at a minimum, the best available ultrasonic examination method on the 'B' and 'C' hot leg nozzle-to-pipe welds during the Spring 2002 refueling outage (RF13). The January 9, 2001 letter also informed the NRC of the intention to apply the MSIP™ mitigation strategy on the hot leg piping to mitigate future crack growth. To demonstrate weld integrity and satisfy docketed commitments, inspections of the 'B' and 'C' hot leg nozzle safe end-to-pipe welds were completed in Spring 2002 (RF13), prior to implementing the MSIP™ mitigation strategy, using enhanced ultrasonic (UT) and eddy current testing (ET) examination techniques. The pre-MSIP™ non-destructive examination (NDE) results from RF13 were submitted to the NRC staff on May 4, 2002 (ADAMS Accession No. ML021300106), specifying no significant new indications were identified, and in some cases, the existing indications were characterized as smaller. During RF13, the MSIP™ mitigation strategy was applied to the 'B' and 'C' hot leg piping. Post-MSIP™ NDE performed during RF13 identified no new indications and the NRC was subsequently notified (ADAMS Accession No. ML021360139) of the results.

As previously committed, post-MSIP™ ASME Code, Section XI Inservice Inspection of the reactor vessel hot leg and cold leg dissimilar metal welds was completed during the Fall 2003 refueling outage (RF14) to verify the MSIP™ mitigation strategy effectiveness. The results demonstrated that the previously identified indications were identified and characterized, and that there was no crack growth on those indications. Subsequently, to meet commitments and the requirements of ASME Code Case N-770, volumetric inspections were performed on both 'B' and 'C' hot leg nozzle-to-pipe dissimilar metal welds and on the three cold leg nozzle-to-pipe dissimilar metal welds with the most recent inspections performed in Fall 2021 (RF26). No detectable changes were identified when compared to the previous examination reports.

2. In Spring 2008 (RF17), FSWOLs were applied to the pressurizer relief, safety, spray, and surge nozzles. Volumetric examinations of these FSWOLs were performed in Spring 2011 (RF19) per the RI-ISI program. In Spring 2020 (RF25), volumetric examinations were subsequently performed on the FSWOLs, excluding the surge nozzle FSWOL. This meets the requirement of ASME Code Case N-770 to inspect at least 25% of the population. These UT inspections identified no recordable indications.
3. In Fall 2012 (RF20), UT indications were identified on four CRDM penetrations during performance of volumetric examinations of the reactor vessel closure head. These examinations were performed in accordance with ASME Boiler & Pressure Vessel (BPV) Code Case N-729-1. Repairs were performed on the CRDM penetration nozzles and associated j-groove welds using the Westinghouse Embedded Flaw Repair process, as approved by the NRC. PWSCC was identified as the apparent cause of the flaws. Corrective actions included repairing the penetrations and revising the frequency of the bare metal visual (BMV) exam and the volumetric exam to every refueling outage.
4. In February 2013, in response to industry operating experience involving the missed detection of significant flaws during Section XI, Appendix VIII, Supplement 10 ultrasonic examinations, EPRI issued technical report number 3002000041 (EPRI Report 3002000041), “Nondestructive Evaluation Improvement Focus Group Extent of Condition Actions in Response to North Anna Dissimilar Metal Weld Operating Experience.” The extent of condition (EOC) actions for dissimilar metal (DM) welds in EPRI Report 3002000041 were assigned an NEI 03-08 implementation requirement of “Needed” and included Class 1 DM welds subject to ASME Boiler and Pressure Vessel Code, Section XI, Appendix VIII, Supplement 10, examination. Six reactor pressure vessel nozzle-to-pipe DM welds and six steam generator

nozzle-to-safe end DM welds were determined to be subject to volumetric examination and were assessed using the EOC process provided in EPRI Report 3002000041. The assessment results determined each DM weld was excluded from the EOC for the industry operating event and no further action was required.

5. During September and October 2013, the periodic assessment to confirm industry materials issues-related documents with requirements assigned an NEI 03-08 Revision 2 were appropriately implemented. The assessment recommended one enhancement to capture "Needed" or "Mandatory" guidance and the associated response into the Corrective Action Program, even if it had previously been captured in approved procedures. As a result, the Alloy 600 program owner confirmed EPRI technical reports 3002000204, "Nondestructive Evaluation: Performance Demonstration Initiative (PDI) Guidance for Improved Reliability in Ultrasonic Examinations," and 3002000091, "Nondestructive Evaluation: Guideline for Conducting Ultrasonic Examinations of Dissimilar Metal Welds Revision 1," were evaluated for applicability to the Alloy 600 program and 'Needed' and 'Good Practice' requirements were incorporated as appropriate.

6. In Spring 2014 (RF21), volumetric inspections of the 66 reactor vessel closure head penetrations (65 CRDM and RV closure head vent system line) identified five reactor CRDM penetrations that did not meet the requirements of 10 CFR 50.55a(g)(b)(ii)(D) and American Society of Mechanical Engineers (ASME) Section XI Code Case N-729-1. The indications were not through-wall as confirmed by volumetric and BMV exams. The flaws were repaired using the embedded flaw repair process. in accordance with NRC-approved WCAP-15987-P, Revision 2-P-A and Relief Request RR-4-05. The apparent cause of the flaws was attributed to primary water stress corrosion cracking. These indications were in addition to previous indications that were identified in Fall 2012 (RF20).

7. In Spring 2014 (RF21) and Fall 2018 (RF24), volumetric inspections were performed on the steam generator hot leg nozzle to pipe dissimilar metal welds as required per ASME Code Case N-770. For refueling outages without scheduled volumetric inspections of the steam generator (SG) hot leg nozzle to pipe welds, BMV inspections are performed on these welds. The most recent BMV inspections were performed in Fall 2021 (RF26). These UT and BMV inspections identified no recordable indications. In RF21 and RF24, volumetric (UT) examinations of the three SG cold leg nozzle to pipe dissimilar metal welds were performed as required per ASME Code Case N-770. These UT examination results identified no recordable indications.

8. In May 2017 the industry guidelines provided in EPRI Report 3002002963, Materials Reliability Program: Guideline for Nondestructive Examination of Reactor Vessel Upper Head Penetrations (MRP-384) were evaluated by the station. Subsequently, in December 2019, the industry guidelines provided in EPRI Report 3002017288, Materials Reliability Program: Guideline for Nondestructive Examination of Reactor Vessel Upper Head Penetrations, Revision 1 (MRP-384) were reviewed by the Fleet NDE Lead. As a result of these reviews, the NEI 03-08 "Good Practice" and "Needed" recommendations were incorporated into the Alloy 600 program procedure and fleet NDE procedures.
9. In Spring 2017 (RF23), the reactor vessel closure head was replaced. BMV inspections of the replacement reactor vessel closure head required per ASME Code Case N-729 were performed in Fall 2021 (RF26). These inspection results were acceptable.
10. In Fall 2021 (RF26), BMV inspections were performed on the reactor vessel BMI penetrations. The BMI visual inspections are performed every other refueling outage as required per ASME Code Case N-722. These inspection results were acceptable.

The above examples of operating experience provide objective evidence that the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program includes activities to perform visual and volumetric examinations to detect cracking due to PWSCC and loss of material for Alloy 600/82/182 components or welds within the scope of subsequent license renewal and to initiate corrective actions. Occurrences identified under the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

Program Description

The *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program is an existing condition monitoring program that manages loss of fracture toughness of cast austenitic stainless steel reactor coolant pressure boundary components with service conditions above 250°C (Celsius) [482°F (Fahrenheit)].

The program consists of the determination of the susceptibility of CASS piping and piping components in primary pressure boundary with regard to thermal aging embrittlement based on the casting method, molybdenum content, and percent ferrite. Within the reactor coolant loops, the hot leg piping, crossover piping, and cold leg piping contain a total of 18 cast austenitic stainless steel pipe fittings. This population of fittings comprises five elbows and one safety injection accumulator nozzle for each loop. The fittings are statically cast SA351 Grade CF8A (low molybdenum) steel. The three Westinghouse Model 93A reactor coolant pumps each have statically cast single-piece SA-351 Grade CF8 (low molybdenum) steel casings.

Susceptibility of the CASS piping and pump casings was determined using the screening criteria given in the Grimes Letter (ADAMS Accession No. ML003717179) and NUREG-2191, based on the molybdenum content, casting method, and ferrite content. In determining susceptibility of the CASS piping components to thermal aging embrittlement, certified material test report (CMTR) chemistry information was used, and delta ferrite was calculated using Hull's equivalent factors from NUREG/CR–4513 Rev. 1 (August 1994) and Rev. 2 (May 2016). Using this approved methodology, the three reactor coolant pump casings and 18 pipe fittings have estimated ferrite content less than 20% and are thus screened 'out' per NUREG-2191, Table XI.M12-1. Therefore, consistent with NUREG-2191, XI.M12, additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required.

The *PWR Vessel Internals* program (B2.1.7) manages the aging of CASS reactor vessel internals (RVI) components.

NUREG-2191 Consistency

The *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program is an existing program that is consistent with NUREG-2191, Section XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS),” as modified by SLR-ISG-2021-02-MECHANICAL, "Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance."

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In Fall 2003 (RF14), Fall 2009, (RF18), Fall 2015 (RF22), and Fall 2021 (RF26), ultrasonic (UT) inspections were performed on the welds attaching the CASS elbows to the reactor vessel inlet nozzle safe ends. The UT inspections were acceptable with no recordable indications identified in the attached CASS piping.

The above examples of operating experience provide objective evidence that the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program includes activities to perform inspections that meet ASME Code, Section XI inspection requirements to identify and manage loss of fracture toughness with regard to thermal aging embrittlement of the CASS components within the scope of subsequent license renewal and to initiate corrective actions. Occurrences identified under the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.7 PWR Vessel Internals

Program Description

The *PWR Vessel Internals* program is an existing condition monitoring program that manages changes in dimensions, cracking, loss of fracture toughness, loss of material, and loss of preload for the reactor vessel internals (RVI) components within the scope of subsequent license renewal. Cracking includes stress corrosion cracking, primary water stress corrosion cracking, irradiation-assisted stress corrosion cracking, and cracking due to fatigue/cyclic loading. Degradation due to loss of material can be induced by wear, and loss of fracture toughness is the result of thermal aging and neutron irradiation embrittlement. Potential causes for changes in dimensions are void swelling or distortion, and loss of preload can result from thermal and irradiation-enhanced stress relaxation or creep.

The guidelines listed in MRP-227, Revision 1-A, Electric Power Research Institute (EPRI) Technical Report 3002017168, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines,” provide appropriate aging management guidance for RVI components up to a 60-year operating period.

SLR-ISG-2021-01-PWRVI, “Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized Water Reactors,” (ADAMS Accession No. ML19339G350), includes provisions for a *PWR Vessel Internals* program to rely on the use of MRP-227, Revision 1-A as supplemented by a gap analysis to enhance the program for an 80-year operating period, or acceptable guidance such as an approved revision of MRP-227 that considers an operating period of 80 years.

For an 80-year operating period, the *PWR Vessel Internals* program relies on implementation of the inspection and evaluation guidelines in MRP-227, Revision 1-A and EPRI Technical Report 3002018245, “Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals – 2020 Update (MRP-228, Rev. 4)” (ADAMS Accession No. ML19081A058), as supplemented by a gap analysis to manage the aging effects on the RVI components. The EPRI basis document that provides functionality analyses for the aging management methodology is Technical Report 3002007955, “Materials Reliability Program: Functionality Analysis for Westinghouse and Combustion Engineering Representative PWR Internals (MRP-230, Revision 3)” (ADAMS Accession No. ML20244A027). The failure modes, effects, and criticality analysis from EPRI Technical Report 3002013220, “Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Designs (MRP-191, Revision 2)” (ADAMS Accession No. ML19081A060) provides the basis for grouping the reactor internals components into inspection categories by assessing aging effects and relevant time-dependent aging parameters.

Excluding the neutron panel bolts and the irradiation specimen guides and bolts, the neutron exposure of the reactor vessel components for 80 years of operation is bounded by the evaluations in MRP-191, Revision 2. The neutron fluence of the neutron panel bolts and the irradiation specimen guide bolts for the 80 years of operation was determined to be greater that the projections in MRP-191, Revision 2. As a result, a vendor expert panel evaluation determined that the inspection category of 'no additional measures' applies for the neutron panels and irradiation specimen guides.

The gap analysis integrates the applicable interim guidance from MRP 2018-022, "Transmittal of MRP-191 Screening, Ranking, and Categorization Results and Interim Guidance in Support of Subsequent License Renewal at U.S. PWR Plants" (ADAMS Accession No. ML19081A061) for additional inspections of reactor vessel components not listed in MRP-227, Revision 1-A and for inspections of the control rod guide tube (CRGT) C-tubes and sheaths in WCAP-17451-P, Revision 2, "Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections" (ADAMS Accession No. ML19262E593). Following are details of items included in the *PWR Vessel Internals* program based on the gap analysis results:

1. The components below have been incorporated into the *PWR Vessel Internals* program with examinations assigned to the 'primary' inspection category in accordance with MRP-2018-022:
    a. Clevis insert bolts (Alignment and Interfacing Components)
    b. Clevis insert dowels (Alignment and Interfacing Components)
    c. Radial support keys Stellite wear surface (Radial Support Keys)
    d. Clevis bearings Stellite wear surface (Alignment and Interfacing Components)
2. Guidance was incorporated into the *PWR Vessel Internals* program with examinations assigned to the 'expansion' inspection category for the control rod guide tube (CRGT) continuous section sheaths and C-tubes (CRGT Assembly) in accordance with WCAP-17451-P, Revision 2.

The selection of RVI components to be inspected is based on a four-step ranking process that includes the designations of 'primary', 'expansion', 'existing programs' (such as American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, Examination Category B-N-3, examinations of core support structures), or 'no additional measures'. The program includes expanding examinations (i.e., 'expansion' components) if the observed extent of degradation for the 'primary' components exceeds acceptance criteria. The identified examinations for RVI components provide reasonable assurance that the effects of age-related degradation mechanisms will be managed during the period of extended operation.

The *PWR Vessel Internals* program is implemented as a fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *PWR Vessel Internals* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M16A, “PWR Vessel Internals,” as modified by SLR-ISG-2021-01-PWRVI, "Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized Water Reactors."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Detection of Aging Effects (Element 4); Monitoring and Trending (Element 5); and Acceptance Criteria (Element 6)

1. Procedure(s) will be revised to include a list of the components that require inspections for the Primary, Expansion, and Existing Programs categories specified in MRP-227, Revision 1-A.

Parameters Monitored / Inspected (Element 3) and Acceptance Criteria (Element 6)

2. Procedure will be revised to require additional spring height measurements prior to the SPEO to establish the core barrel hold down spring height and determine if replacement of the core barrel hold down spring is required.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *PWR Vessel Internals* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. During the Fall 2009 refueling outage (RF18), the reactor internals core barrel and former plates were modified for an upflow conversion to reduce the differential pressure across the baffle plates. Inspections of the baffle-former bolting during the Fall 2021 (RF26) refueling outage found no visual indications, and found volumetric indications for only seven of the 1088 bolts. No clustering was present.

2. During the Spring 2017 refueling outage (RF23), the reactor vessel head was replaced to reduce susceptibility to PWSCC at the penetrations. The replacement reactor vessel closure head incorporates PWSCC-resistant Alloy 690 piping material and Alloy 52 welding material. The replacement RV closure head also includes a modified design that removed the thermal sleeves, and replaced them with guide sleeves and extension tubes. Since the guide sleeves limit thermal siphoning, inspections for MRP-227, Revision 1-A, are not required.
3. During the Fall 2021 refueling outage (RF26), remote visual examinations and volumetric examinations of the reactor vessel internals were performed for the following components:
    - Control rod guide tube assembly
    - Core barrel welds
    - Lower internals assembly
    - Baffle-former assembly
    - Radial support keys
    - Core barrel hold down spring

    For the majority of these components, there were no relevant indications of degradation. For the baffle-former bolting, seven of the 1088 bolts were evaluated to have relevant indications representative of cracking at the head-to-shank region. Due to the small number of relevant indications and the fact that there was no clustering among those indications, no corrective action was required. The small number of bolts with indications, and the one bolt that was not inspectable with UT due to the surface condition of the bolt head which did not allow adequate seating of the UT probe were confirmed, using an acceptable pattern of baffle-former bolts, to not adversely affect the structural integrity of the internals. The baffle-former assembly retains its structural integrity and remains within its design and licensing basis, with no reduction in its ability to perform its design basis functions. The untestable bolt was not credited for structural integrity of the internals.

    A relevant indication was identified on the radial support key located at the 270-degree position. The relevant indication was the result of interference of the radial support key with the reactor vessel outlet nozzle and the core barrel support ledge during the Fall 2021 refueling outage (RF26) core barrel pull. The damage was not evident during the examination in 2015. The damage was not on the wear surface.

    Based on the results of the core barrel hold down spring height measurements completed during RF26, additional measurements will be performed prior to the SPEO to establish the core barrel hold down spring height and determine if replacement of the core barrel hold down spring is required.

The above examples of operating experience provide objective evidence that the *PWR Vessel Internals* program includes activities to perform visual and volumetric examinations to identify changes in dimensions due to void swelling or distortion, cracking, loss of fracture toughness, loss of material, and loss of preload for the reactor vessel internals components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *PWR Vessel Internals* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *PWR Vessel Internals* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *PWR Vessel Internals* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.8 Flow-Accelerated Corrosion

Program Description

The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion, as well as wall thinning due to erosion mechanisms. Erosion monitoring is performed for the internal surfaces of metallic piping and components to manage wall thinning due to cavitation, flashing, liquid droplet impingement, and solid particle erosion.

The *Flow-Accelerated Corrosion* program is consistent with NRC Generic Letter 89-08 (GL 89-08), "Erosion/Corrosion-Induced Pipe Wall Thinning," and relies on implementation of the EPRI guidelines in Nuclear Safety Analysis Center (NSAC)-202L, Revision 4, "Recommendations for an Effective Flow Accelerated Corrosion Program." The erosion activity implements the recommendations of EPRI 3002005530, "Recommendations for an Effective Program Against Erosive Attack".

The *Flow-Accelerated Corrosion* program includes (a) identifying flow accelerated corrosion (FAC)-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 inspection; (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 *Flow-Accelerated Corrosion* program tracks and predicts occurrences of wall thinning due to FAC using CHECWORKS-SFA™ (SFA: Steam/Feedwater Application) software. Changes made in the CHECWORKS-SFA™ model are prepared and implemented by a qualified FAC engineer. Each change is then independently reviewed and validated by a qualified FAC engineer. Evaluations documenting the calculation of wear, wear rate, remaining life, next scheduled inspection, and sample expansion are independently reviewed by a qualified FAC engineer. The CHECWORKS-SFA™ model is evaluated and updated, as required, to reflect any significant changes in plant operating parameters such as power uprates. The CHECWORKS-SFA™ model is also refined by importing actual ultrasonic testing (UT) examination results as input for further wear rate analysis, thereby improving the predictive capability of the model for FAC-susceptible components included in the model. Wall thinning information available from the CHECWORKS-SFA™ software is one of the tools used to determine the scope and required schedule for inspections of FAC-susceptible components.

In addition to planned inspections performed for the *Flow-Accelerated Corrosion* program, opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation. The *Flow-Accelerated Corrosion* program goal is to ensure that piping remains above the minimum allowable wall thickness. In support of that goal, inspections are scheduled such that the component wall thickness is managed until replacement occurs.

Erosion Monitoring Description

The basis for erosion monitoring is an Erosion Susceptibility Evaluation (ESE) that identifies components that require inspection due to potential wall thinning caused by cavitation, flashing, liquid droplet impingement (LDI), or solid particle erosion (SPE). The ESE includes each system that could be degraded by any of these four mechanisms. The majority of the erosion monitoring inspection scope is based on the ESE, and is determined in a manner similar to the process for 'Susceptible Non-modeled' (SNM) lines used for the FAC program. Lines are risk ranked based on the level of plant safety, erosion susceptibility, and consequence of failure. An additional input for identifying the scope of inspections is an engineering evaluation of components that are not susceptible to erosion because of infrequent operation. The engineering evaluation also considers non-routine system alignments which could increase erosion susceptibility.

Identification of components to be inspected for erosion monitoring is provided by an Engineering evaluation that considers operating experience reviews, components replaced at other units, re-inspections of previously-inspected components, input from other internal inspections, and previously-replaced components. Erosion monitoring includes calculations of wear rate based on nominal and measured wall thickness values, evaluations of remaining service life, and determination of whether a component requires immediate replacement, a future re-inspection, or no further inspection.

The CHECWORKS-SFA™ Erosion Module is not used to determine susceptibility, or choose systems for inspection. Lines modeled in the Erosion Module are identified using the ESE. The outputs from the Erosion Module are used to predict locations on susceptible lines. Those outputs are not used to exclude lines from the inspection scope, but are used to help establish the priority of inspections. Determination of remaining service life or projected wall thickness is accomplished using engineering evaluations performed outside of the Erosion Module.

While no preventive actions are required by this program, activities such as monitoring of water chemistry to control pH and dissolved oxygen content can be effective in reducing FAC. Similarly, selecting FAC-resistant materials, or changing piping geometry for susceptible locations can be effective in reducing FAC. The aging management strategy related to FAC emphasizes a preference for design improvement over simple management of wall thinning.

The *Flow-Accelerated Corrosion* program is implemented as a Fleet program at Dominion Energy. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196), and determinations were made for each station that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Flow-Accelerated Corrosion* program is an existing program that is consistent with NUREG-2191, Section XI.M17, “Flow-Accelerated Corrosion.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Flow-Accelerated Corrosion* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

FAC Operating Experience:

1. In May 2011, a 12-inch diameter feedwater heater drain pipe had a measured wall thickness that was less than the minimum allowable thickness. The projected wall thickness at the next refueling outage in Fall 2012 (RF20) was evaluated to determine whether continued operation until RF20 was acceptable. Continued operation was confirmed based on a new minimum allowable wall thickness calculated by Design Engineering.
2. In May 2011, significant wear due to FAC was identified on an 18-inch diameter feedwater pipe segment. Screening of the component per ASME Code, Section XI, Code Case N-597 determined it was acceptable for the pipe segment to remain in service. Per Code Case N-597, “the projected thickness at the next refueling outage (RFO) at any location should not be less than 90% of the minimum wall thickness of the piping item required for design pressure”. The projected wall thickness at the next RFO was greater than 90% of the minimum required wall thickness. The component was included on the FAC inspection list for the next RFO, and was labeled to be inspected at each RFO until replaced.
3. In November 2012, a leak was identified in a main steam drain line due a hole in a 1-inch pipe elbow. The other main steam drain lines susceptible to this degradation had been replaced with FAC-resistant chrome-moly. An in-kind (carbon steel) replacement of the affected piping was performed in Fall 2012. Subsequently, in Spring 2014, the piping was again replaced but with FAC-resistant chrome-moly.

4. In June 2013, an internal assessment was performed for the FAC program. The overall conclusion of the assessment was that the FAC program satisfied the requirements of NRC Generic Letter 89-08. An Area for Improvement (AFI) identified by the assessment indicated that material changes due to replacements did not always result in drawing updates to reflect the change. A search of work order history discovered drawing updates were still required for one-third of the work orders that implemented material replacements. The drawing updates were completed in 2015. Additionally, a procedure revision for the FAC program was completed to require initiation of a CR to revise drawings to reflect the updated plant configuration as FAC-susceptible components are replaced.
5. In September 2015, a steam leak was identified at a piping elbow downstream of a feedwater heater vent header orifice inlet. The vent header piping is Category 1 susceptible non-modeled pipe which means that it is highly susceptible to FAC. The leak was located at a weld (heat affected zone) which indicates that the leak was not caused by FAC although FAC could have been a contributor. The two elbows immediately downstream of the elbow where the leak occurred were examined but no indications of wear were found. Since the leak was determined to not be caused by FAC, the existing carbon steel piping was replaced with carbon steel.
6. In June 2016, an expander in the feedwater heater drain system experienced wear due to FAC and the entrance effect. The wear was suspected to have accelerated in the expander after the reducer immediately upstream was replaced with FAC-resistant chrome-moly. Wear rate estimates for the expander were used to conclude that the expander would be acceptable for the remainder of the operating cycle until the carbon steel piping and fittings could be replaced. The expander and associated fittings were replaced with chrome-moly during the Spring 2017 refueling outage (RF23).

Erosion Operating Experience:

7. In December 2009, noises that indicated possible cavitation were detected in the vicinity of a control valve in the line from a deaerator to the condenser. Leakage at the valve was subsequently noted during the operating cycle in Spring 2010. A hole was identified through the bottom of the carbon steel valve, and a repair was completed by welding a steel plate over the exterior of the hole in Spring 2010. Noises indicating possible cavitation were noted again in Spring 2011. The valve was replaced with a new carbon steel valve during the Spring 2011 refueling outage (RF19).

   During the Fall 2012 refueling outage (RF20), an inspection by Engineering confirmed the presence of cavitation on the interior of the valve body. Weld buildup of the affected area was completed using carbon steel during that outage.

During the Spring 2014 refueling outage (RF21), inspection again identified cavitation damage. Weld buildup was performed, but stainless steel was used instead of carbon steel to provide improved resistance to cavitation damage.

The valve was replaced in 2017, and no subsequent indication of leakage has been identified.

8. In January 2016, a hole was identified on an elbow in the recirculation piping for a service water booster pump. The hole was caused by cavitation damage due to the 45-degree elbow being located immediately downstream of a flow restricting orifice. UT wall thickness measurements for that section of piping had not been included in the scope of inspections but were added. The damaged section of carbon-steel piping containing the elbow was replaced with carbon steel. An extent of condition evaluation identified the only additional flow restricting orifices with an elbow immediately downstream were located in the cross-connected piping used to provide a back-up source of water from the fire service system to the service water system. This piping is normally stagnant because the fire service system is only used to supply water to the service water system if service water is unavailable to cool the diesel generators. Therefore, these piping segments are not included in the service water monitoring program.

The above examples of operating experience provide objective evidence that the *Flow-Accelerated Corrosion* program includes activities to perform visual and volumetric examinations to identify wall thinning caused by flow-accelerated corrosion and wall thinning caused by erosion mechanisms for components within the scope of subsequent license renewal, and to initiate corrective actions. Program activities (a) identify susceptible piping systems and components; (b) develop FAC predictive models to reflect component geometries, materials, and operating parameters; (c) perform analyses of FAC models and, with consideration of operating experience, select a sample of components for inspection; (d) inspect components; (e) evaluate inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporate inspection data to refine FAC modeling. Occurrences identified under the *Flow-Accelerated Corrosion* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Flow-Accelerated Corrosion* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Flow-Accelerated Corrosion* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.9 Bolting Integrity

Program Description

The *Bolting Integrity* program is an existing condition monitoring program that manages aging by performing periodic visual inspections for indications of cracking, loss of material due to general, pitting and crevice corrosion, microbiologically influenced corrosion, wear, and loss of preload as evidenced by leakage for safety-related and nonsafety-related closure bolting on pressure-retaining components within the scope of subsequent license renewal.

The preventive actions associated with this program include proper selection of replacement bolting material; the use of appropriate lubricants and sealants is consistent with the guidelines of EPRI Report 1015336, "Nuclear Maintenance Application Center: Bolted Joint Fundamentals," and EPRI Report 1015337, "Nuclear Maintenance Application Center: Assembling Gasketed Flanged Bolted Joints," along with additional recommendations consistent with NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants" and EPRI report NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," with exceptions noted in NUREG-1339 for safety-related piping; consideration of minimum specified yield strength when procuring bolting material; lubricant selection (e.g., not allowing the use of molybdenum disulfide); proper torquing of bolts; checking for uniformity of the gasket compression after assembly; and application of an appropriate preload consistent with guidance in EPRI documents, manufacturer recommendations, or engineering evaluation. These actions preclude loss of preload, loss of material, and cracking.

The *Bolting Integrity* program includes the following additional considerations consistent with NUREG-1339 and EPRI NP-5769:

- Visual examinations are performed in accordance with the *Boric Acid Corrosion* program (B2.1.4) to detect degradation of pressure boundary bolting caused by boric acid leakage.
- Visual and volumetric examinations are performed in accordance with the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) to detect degradation of pressure boundary bolting due to stress corrosion cracking.

Guidance from EPRI Report 1015336 (Table 4-9) is included in the *Bolting Integrity* program, as indicated by the following tasks performed by the program:

- Examine surface areas, especially the thread root area, for evidence of corrosion, cracking, galling, pitting, and mechanical damage.
- Inspect assemblies for proper thread engagement, correct size, proper lubricant and torque values during maintenance, where specified.
- Examine code material requirements, bolt and nut markings, and material identification.

Recommendations from EPRI Report 1015337 are followed for assembling bolted connections. Preventive measures to preclude or minimize cracking and loss of preload include proper selections of bolting material and lubricant, and proper application of preload.

The program activities provide for aging management of closure bolting on pressure-retaining components within the scope of subsequent license renewal. The program includes periodic inspection, at least once per refueling cycle, of closure bolting on pressure-retaining components for indication of loss of preload, cracking, and loss of material due to corrosion. The program also credits visual inspection of pressure-retaining bolted joints in ASME Class 1, 2, and 3 systems for leakage and age-related degradation during system pressure tests performed in accordance with ASME Code, Section XI. In addition, the *Bolting Integrity* program credits volumetric, surface, and visual inspections of ASME Code, Section XI, Class 1, 2, and 3 bolts, nuts, washers, and other associated bolting components performed in accordance with ASME Code, Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. The integrity of ASME and non-ASME pressure-retaining bolted joints which contain fluids such as water, oil, or steam is assessed by detection of visible leakage, evidence of past leakage, or other age-related degradation during walkdowns and maintenance activities. Conditions such as degraded bolts, nuts and threads, active leakage, high noise levels, loose or missing bolts and nuts, evidence of past leakage, damaged insulation, discoloration, or other age-related degradation are entered into the Corrective Action Program where the condition is evaluated.

There is no high-strength bolting (i.e., pressure boundary bolting with actual yield strength greater than 150 kilo-pounds per square inch) or bolts with unknown yield strength within the scope of the *Bolting Integrity* program, therefore sample based volumetric inspection of closure bolting greater than 2 inches in diameter to detect indications of cracking is not applicable.

Three categories of closure bolting may preclude detection of joint degradation during normal system walkdowns. These categories include closure bolting located in submerged environments, closure bolting for systems containing air or gas for which leakage is difficult to detect, and closure bolting for systems not normally pressurized. Closure bolting for each category will be visually inspected for loss of material during maintenance activities. Bolt heads will be inspected when made accessible, and bolt threads inspected if joints are disassembled. Details regarding inspection requirements for each category are provided below.

- Components with submerged bolting include the fuel transfer tube gate valve, cavity seal ring, pump casings and columns for the service water pumps and fire service pumps, circulating water pump suction pit isolation valves, and various sump pumps. In each 10-year period during the subsequent period of extended operation, a representative sample of bolt heads and threads is inspected up to a maximum of 25 bolts for each material and environment combination. For submerged pump bolting, if opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 25 bolt heads and threads over a 10-year period, then periodic pump vibration measurements are taken and trended.

- Air or gas systems include the station service air and instrument air systems, and various systems using instrument air, emergency diesel generator starting air, safety injection and other systems using nitrogen, systems containing refrigerant, and carbon dioxide systems for fire protection. For air or gas systems, inspections are performed consistent with that of submerged closure bolting. In each 10-year period during the subsequent period of extended operation, a representative sample of bolt heads and threads is inspected up to a maximum of 25 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 25 bolt heads and threads over a 10-year period, then soap bubble testing will be performed.
- Piping systems having a pressure boundary or leakage boundary intended function but not normally pressurized are identified with an 'air - indoor uncontrolled' internal environment (e.g., piping downstream from vents and drain isolation valves, piping associated with building airlocks, hydrogen removal, fire service deluge, fuel transfer tube, leak rate testing piping, and reactor building spray piping and nozzles). For this category of bolting, the torque of the bolting will be checked to the extent that the closure bolting is not loose. In each 10-year period during the subsequent period of extended operation, a representative sample of bolt heads and threads is inspected up to a maximum of 25 bolts for each material and environment combination.

For sampling-based inspections, if the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment, additional inspections are conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections is determined in accordance with the Corrective Action Program; however, no fewer than five additional (or 20%, whichever is less) inspections of different components having the same material/environment combination are required for each inspection that does not meet the acceptance criterion. The additional inspections are to be completed within the same 10-year inspection interval. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies will be adjusted as determined by the Corrective Action Program.

Inspections and tests will be 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 procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) includes inspections of closure bolting within the scope of ASME Code, Section XI, and supplements this *Bolting Integrity* program. The following aging management programs manage aging effects associated with safety-related and nonsafety-related structural bolting:

- *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program (B2.1.13)
- *ASME Section XI, Subsection IWE* program (B2.1.30)
- *ASME Section XI, Subsection IWF* program (B2.1.32)
- *Structures Monitoring* program (B2.1.35)
- *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.36)

NUREG-2191 Consistency

The *Bolting Integrity* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M18, "Bolting Integrity."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Parameters Monitored / Inspected (Element 3); Detection of Aging Effects (Element 4)

1. Procedure(s) will be revised to specify instructions for performing inspections of pressure boundary bolting for locations that preclude detection of joint leakage including bolting in submerged environments, bolting for air or gas systems, and bolting for piping systems not normally pressurized as follows:
    a. Submerged closure bolting is visually inspected for loss of material during maintenance activities. In this case, bolt heads are inspected when made accessible, and bolt threads are inspected when joints are disassembled. In each 10-year period during the subsequent period of extended operation, a representative sample of bolt heads and threads is inspected up to a maximum of 25 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 25 bolt heads and threads over a 10-year period, then periodic pump vibration measurements are taken and trended.

b. For air or gas systems, inspections are performed consistent with that of submerged closure bolting. Closure bolting for air or gas systems is visually inspected for loss of material during maintenance activities. In this case, bolt heads are visually inspected when made accessible, and bolt threads are visually inspected when joints are disassembled. In each 10-year period during the subsequent period of extended operation, a representative sample of bolt heads and threads is inspected up to a maximum of 25 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 25 bolt heads and threads over a 10-year period, then soap bubble testing will be performed.

c. For piping systems not normally pressurized, the torque of the bolting will be checked to the extent that the closure bolting is not loose. In each 10-year period during the subsequent period of extended operation, a representative sample of bolt heads and threads is inspected up to a maximum of 25 bolts for each material and environment combination.

Detection of Aging Effects (Element 4)

2. Procedure(s) will be revised to:

   a. Include inspections of pressure-retaining bolting in inaccessible areas when they become accessible by means such as excavation, dewatering, or shielding/barrier removal.

   b. Include a requirement during opportunistic maintenance activities to document the condition of bolt heads and threads.

3. Procedure(s) will be revised to specify inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task.

Monitoring and Trending (Element 5); Acceptance Criteria (Element 6); Corrective Actions (Element 7)

4. Procedure(s) will be revised to evaluate sampling-based inspections against plant-specific acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies will be evaluated and adjusted as determined by the Corrective Action Program. Bolting that is unsuitable for continued use will be replaced. If the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment, additional inspections will be conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections will be determined in accordance with the

Corrective Action Program; however, there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material and environment combination is inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material and environment combination and will be completed within the 10-year inspection interval in which the original inspection was conducted.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Bolting Integrity* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In August 2012, the NRC issued Information Notice 12-15 (IN 12-15), “Use of Seal Cap Enclosures to Mitigate Leakage from Joints that Use A-286 Bolts,” to inform licensees of the potential issues associated with the installation of seal cap enclosures to mitigate leakage from A-286 bolted connections. An unintended consequence of installation of seal cap enclosures was cracking due to the stress corrosion cracking resulting from submergence of Alloy A-286 (Grade 660) flange bolting in leaked primary coolant. Following issuance of IN 12-15, the PWR Owners Group (PWROG) issued Letter OG-12-330, “Generic Guidance for Valves that have Seal Encapsulation Devices Installed.” PWROG Letter OG-12-330 provides guidance related to IN 12-15 and recommends that owners identify the population of ASME Class 1 and 2 bolted bonnet check valves employing encapsulation devices, document an examination plan for all valves left in service with encapsulation devices installed, and examine the encapsulation devices that will be left in service. Based on a plant review, it was determined that there are no valves that have seal cap enclosures installed. Therefore, the recommendations of OG-12-330 have been addressed and no further actions were required regarding the use of seal caps.
2. In April 2014, during installation of inspection port on 'A' steam generator, it was noted that a bolt hole exhibited thread deformation starting at approximately 3/16-inch from the inspection port face extending to 1/2-inch from the face. Per the installation procedure, the stud is installed to the full thread engagement less one turn (or one thread). This leaves 2.2 threads above the minimum required thread engagement and the damage did not represent more than 1/4 of a thread. Engineering determined the damage did not represent a reduction in the ability of the hole to hold the required preload and stresses in the joint.

3. In January 2015, the NRC issued Regulatory Issue Summary (RIS) 2015-01, “Qualification Requirements for Bolt and Stud Non-Destructive Examinations,” which summarized the inconsistencies between the EPRI Performance Demonstration Initiative (PDI) methodology and the ASME Code, Section XI requirements. Following issuance of RIS 2015-01, NEI 03-08 “Needed” elements were identified by the EPRI Materials Reliability Program (MRP) which identified the required PDI Site Demonstration Protocol for Bolting. In February 2016, the NEI 03-08 “Needed” requirements were implemented into ISI Program documents emphasizing the requirement for blind demonstration of bolting exams per the requirements of NRC RIS 2015-01 and additional MRP guidance.
4. In October 2016, during plant walkdown, the NRC identified boron on the body to bonnet bolted connection of the 'B' high head injection valve. A significant amount of boron had accumulated at the body to bonnet connection, onto the valve body, and onto the adjacent 'A' high head injection valve. The leak was inspected and evaluated as required by the Boric Acid Corrosion program. The leak was identified as active, but not quantifiable. There was no contact with carbon steel or low alloy steel components. A catchment basin was placed below the leak and during the following refueling outage the boron was cleaned, gasket replaced, and bolts torqued.
5. In April 2017, during performance of periodic boric acid corrosion inspections, boron was discovered on the bolting area of the 'A' reactor coolant loop normal letdown isolation valve. The leak was inspected and evaluated as required by the Boric Acid Corrosion program. The boron was characterized as non-active and dry. The boron was cleaned according to procedure and a torque check was determined to be unnecessary.
6. In October 2018, during refurbishment of the 'A' main steam header safety valve, minor galling to the thread was identified on one of the inlet flange studs. The stud was replaced under the ASME Code, Section XI Repair/Replacement program.
7. In May 2019, EPRI Letter MRP 2019-016 was sent to the MRP committee members to advise the membership of a change in the PDI Site Demonstration Protocol for Bolting to provide a consistent implementation strategy. As a result, the NEI-03-08 “Needed” element documented within EPRI NDE PDI Program was revised to recognize the acceptance ASME Code Case (CC) N-845, “Qualification Requirements for Bolts and Studs, Section XI, Division 1.” The “Needed” element was implemented by incorporating ASME CC N-845 into ISI Program documents.

The above examples of operating experience provide objective evidence that the *Bolting Integrity* program includes activities to perform visual inspections for indications of cracking, loss of material and loss of preload for pressure-retaining closure bolting within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Bolting Integrity* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Bolting Integrity* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Bolting Integrity* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.10 Steam Generators

Program Description

The *Steam Generators* program is an existing condition monitoring program that manages cracking, loss of material (e.g., wall thinning), and reduction of heat transfer for the steam generators (SGs). The scope of the program includes primary-side components (e.g., U-tubes, tube plugs, channel head divider plate, channel head, tubesheet, etc.), and secondary-side components that are contained within the SG. The *Steam Generators* program does not include primary-side sleeves since these components are not used in the SGs. The program uses volumetric inspections for the tubes, and visual inspections for the other primary-side and secondary-side components. The visual inspections of primary-side components listed above are performed in accordance with the Degradation Assessment (DA) that is prepared as each SG is scheduled for examination.

The *Steam Generators* program utilizes industry endorsed guidance regarding tube inspections, evaluation and repair, and leakage monitoring techniques to ensure tube integrity of the SGs. Aging is managed through assessment of potential degradation mechanisms, inspections, tube integrity assessments, plugging and repairs, primary-to-secondary leakage monitoring, maintenance of secondary side component integrity, primary-side and secondary-side water chemistry, and foreign material exclusion. Implementing procedures specify the performance criteria for tube integrity, condition monitoring requirements, inspection scope and frequency, acceptance criteria for the plugging or repair of flawed tubes, acceptable tube repair methods, leakage monitoring requirements, and operational leakage and accident-induced leakage requirements from the Technical Specifications (TS).

Provisions in the *Steam Generators* program address reporting criteria, inspection scope and frequency, assessments, plugging criteria, and water chemistry monitoring to maintain consistency with established requirements. Those requirements appear in the following documents:

- Technical Specifications (and Technical Requirements Manual)
- Maintenance Rule (10 CFR 50.65)
- EPRI 3002020909, “Steam Generator Integrity Assessment Guidelines”
- EPRI 3002007572, “PWR Steam Generator Examination Guidelines”
- EPRI Technical Report TR1022832, “PWR Primary-to-Secondary Leak Guidelines”
- EPRI 3002007856, “Steam Generator In-Situ Pressure Test Guidelines”

The EPRI guidelines provide a generic industry program to implement the expectations from NEI 97-06, Revision 3, “Steam Generator Program Guidelines.”

The original SGs were replaced in 1994 during RF8. The replacement SGs incorporated Alloy 690 thermally-treated tubes to improve reliability and minimize aging.

The *Steam Generators* program includes plant-specific SG DAs that identify existing and potential degradation mechanisms and associated aging effects that could impact the integrity of the SGs. The DA identifies qualified tube inspection techniques and defines the scope of inspections that are appropriate for the detection and characterization of those aging effects, which consist of cracking, loss of material (e.g., wall thinning), and reduction of heat transfer. As stated in the DA, U-tube and primary-side inspections are performed every third refueling outage for each SG, thus satisfying the guidance for inspections to be performed at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections. The DA includes a review of applicable industry and plant-specific operating experience which has occurred since the previous DA was performed. The DA review determines the existence of any unaddressed mechanism that could adversely affect SG primary-side or secondary-side integrity, as well as the effects of any chemistry excursions or transients that could affect existing degradation mechanisms. An excursion of secondary chemistry could lead to fouling of heat transfer surfaces and a reduction of heat transfer performance.

The DA indicates that primary-side inspections include video/visual examinations, specifically including:

- Tube plugs
- Tube-to-tubesheet welds
- Stub runner and divider plate
- Stub runner to divider plate weld
- Stub runner to tubesheet clad weld
- Divider plate-to-channel head clad weld
- Tubesheet cladding
- Closure ring welds
- Bottom of the bowl cladding (channel head cladding)

The analysis of the SG tube-to-tubesheet welds and the channel head design and loading provided by EPRI Technical Report 3002002850, “Steam Generator Management Program: Investigation of Crack Initiation and Propagation in the Steam Generator Channel Head Assembly” is applicable and bounding. A plant-specific aging management program is not required for the primary-side channel heads. The SG tubesheets are clad with Alloy 82, and the Alloy 690 thermally treated tubes are joined to the tubesheets with autogenous welds. General visual inspections of the tubesheet region looking for evidence of cracking (e.g., rust stains on the tubesheet cladding) are performed as part of this program.

The *Steam Generators* program includes preventive measures to mitigate aging related to corrosion phenomena through foreign material exclusion as a means to inhibit tube degradation due to wear. Identification of deposits on the secondary side of the SGs, and the subsequent removal of sludge deposits help avoid tube degradation. Sludge mapping occurs when the SGs are inspected, and inspections for remaining foreign material are performed after sludge lancing is completed. Sludge lancing, steam drum inspections, and feedring inspections typically are performed at least every third refueling outage. As an additional preventive measure, the *Water Chemistry* program (B2.1.2) monitors and controls reactor water chemistry and secondary water chemistry for the SGs consistent with EPRI 3002000505, “PWR Primary Water Chemistry Guidelines,” and EPRI 3002010645, “PWR Secondary Water Chemistry Guidelines.”

The following TS requirements have been incorporated in the *Steam Generators* program:

- Conducting condition monitoring assessments for each refueling outage during which steam generator tubes are inspected or plugged
- Maintaining steam generator tube integrity by meeting performance criteria for tube structural integrity, accident-induced leakage, and operational leakage
- Installing plugs in tubes found by inservice inspection to contain flaws with a depth equal to, or exceeding, 40% of the nominal tube wall thickness
- Performing periodic inspections of steam generator tubes. Inspection scope, methods, and interval ensure that tube integrity is maintained until the next planned inspection
- Monitoring primary-to-secondary leakage
- Monitoring secondary water chemistry to ensure controls are in place to inhibit SG tube degradation

Non-destructive examination techniques are used to inspect tubing materials in order to identify tubes that may need to be removed from service in accordance with the TS. The *Steam Generators* program uses volumetric examinations for the tubes, and visual inspections for other primary-side and secondary-side components. The *Steam Generators* program defines specific inspection techniques, and describes criteria for the qualification of personnel, and for the acquisition and analysis of data.

Assessment of tube integrity and plugging criteria of flawed tubes is in accordance with plant TS and the *Steam Generators* program implementing procedures. Tube plugs with indications of aging are evaluated for corrective actions in accordance with the Corrective Action Program and the *Steam Generators* program.

Condition monitoring and performance monitoring assessments are performed to determine whether structural and accident leakage criteria have been satisfied during the previous operating cycle(s). Operational assessments are performed after inspections are completed to verify that structural and leakage integrity will be maintained for the operating interval between inspections, which is selected in accordance with the TS and EPRI Steam Generator Integrity Assessment Guidelines. Comparison of the results of the condition monitoring assessment with the predictions of the previous operational assessment provides feedback for evaluation of the adequacy of the operational assessment and additional insights that can be incorporated into the next operational assessment. The condition monitoring and performance monitoring methods are effective in detecting the applicable aging effects, and the frequency of monitoring is adequate to prevent significant age-related degradation.

The *Steam Generators* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Steam Generators* program is an existing program that is consistent with NUREG-2191, Section XI.M19, “Steam Generators.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Steam Generators* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2012, NSAL-12-1, “Steam Generator Channel Head Degradation,” was issued to describe degradation of the SG channel head cladding in a Westinghouse-designed steam generator. Recommended action from NSAL-12-1 was to perform a visual inspection to identify potential breaches in the cladding. Since steam generator bowl scans of each channel head are performed during primary-side inspections, it was determined that no action was necessary.

2. In October 2012, prior to RF20, the RF18 Steam Generator Degradation and Operational Assessments were reviewed as required to validate the steam generator inspection interval. The review, performed per EPRI Steam Generator Integrity Assessment Guidelines, concluded that the current inspection interval of every three refueling cycles remained adequate for both primary and secondary side SG inspections.
3. In April 2014, during eddy current examination in 'C' SG, two tubes were noted as having small indications of wear, possibly caused by a transient loose part within the tube bundle. No loose parts associated with this wear were found in the vicinity of these indications during foreign object search and retrieval activities. Therefore, it was concluded that the loose part no longer remained in the SG. A review of the eddy current data from surrounding tubes was conducted with no additional indications discovered. Examination scope expansion was deemed unnecessary based on the lack of similar indications reported during the inspection, shallow nature of the noted indications, no foreign object was found in the SG, and consultation with vendor engineering,
4. In July 2015, EPRI issued information letter SGMP-IL-15-01, “Steam Generator ASME Code Pressure Boundary Tubesheet Weld or Tube-to-Tubesheet Friction Joint,” to inform the industry that, based on 2014 operating experience, certain replacement U-bend SGs had been designed with the tube-to-tubesheet friction joint as the pressure boundary rather than the welded joint. Engineering confirmed that the tubesheet weld was used as the pressure boundary between primary and secondary sides in the replacement SGs and stress/fatigue analyses of the weld required by the ASME Code had been performed.
5. In October 2016, EPRI issued SGMP-IL-16-02, “Changes to Aging Management Guidance for Steam Generator Channel Head Components,” to inform the industry of NRC draft Interim Staff Guidance (ISG) accepting the conclusions of the Steam Generator Management Program's (SGMP) investigation into the initiation and propagation of cracking in steam generator channel head components. Existing aging management of the SGs included general visual inspections of the channel head bowl. Therefore, Engineering determined the plant-specific aging management recommended in SGMP-IL-16-02 was not required for the divider plate assembly or the tube-to-tubesheet welds.
6. In March 2017, prior to RF23, the RF21 Steam Generator Degradation and Operational Assessments were reviewed as required in order to validate the inspection interval. This review included consideration of industry operating experience and site events that occurred during Cycle 23 which could have a potential impact on steam generator tube integrity prior to the next scheduled steam generator inspections in RF24. The overall conclusion of the review was that steam generator primary and secondary inspections were not required in RF23.

7. In October 2018 (RF24), following identification of loose part wear and possible loose parts in two SGs during inspections, it was determined that the base array probe inspection scope would be expanded to 100% hot leg array probe examination in each SG. Additionally, the hot leg sludge region was also included in the array probe base inspection scope. The expanded inspection would detect foreign objects and foreign object degradation at susceptible locations at the top of the tubesheet. The RF24 Condition Monitoring and Operational Assessment (CMOA) discussed this scope expansion and cataloged the tube wear and foreign object search and retrieval results. Two foreign object wear locations were detected in 'A' SG and two in 'B' SG. One tube was plugged in 'A' SG with a wear depth of 45% through-wall, and one tube was plugged in 'B' SG with a wear depth of 43% through-wall. One tube was preventively plugged in 'A' SG due to an irretrievable foreign object with resultant 7% through-wall wear depth. Five tubes in the 'A' SG had no detectable wear but were preventively plugged due to irretrievable foreign objects. No foreign objects were found in the 'B' SG, and a 2-inch length of wire was removed at the 'C' SG tubesheet. Two tubes were preventively plugged in the 'C' SG.
8. In October 2018, the secondary side of the SGs were inspected during RF24. Heavy corrosion product deposits were found within the tube support plate (TSP) broaches/openings, resulting in 40% estimated flow area blockage. A prior inspection eight years earlier during RF18 estimated less than half as much deposition as in RF24. Based upon the magnitude of the deposits and the inspection results of the SGs obtained during RF24, an SG analysis was performed. The analysis indicated that SG secondary side deposition was adversely impacting flow characteristics and heat transfer. The broach blockage had impacted the secondary flow characteristics of the SGs by redirecting flow laterally through the tube bundle, instead of the normal flowpath vertically along the tubes. This blockage contributed to increased TSP wear indications, new tube denting, and a minor increase in indicated wide range water level. Due to the secondary side SG deposit buildup, steam pressure had decreased since SG replacement in 1994 until there was limited margin (~10-15 psi) to the main turbine control valves full open condition. An evaluation determined that the SGs would soon require secondary side chemical cleaning to mitigate secondary deposits and increase SG pressure margin to the main turbine control valves full open condition. Chemical cleaning using deposit minimization treatment (DMT) was performed on the SGs during RF25 in Spring 2020. Following DMT and ascension to 100% power, main steam pressure increased to ~974 psig with a corresponding #4 turbine control valve position of approximately 40.4%. At the end of Cycle 25, prior to power reduction for RF25, main steam pressure was ~959 psig with a corresponding #4 control valve position of approximately 61.6%. To reduce future secondary side deposition and the need for additional chemical DMT cleanings, an SG chemical dispersant injection system is planned for installation in a future outage.

The above examples of operating experience provide objective evidence that the *Steam Generators* program includes activities to perform volumetric and visual inspections to identify cracking, loss of material, and reduction of heat transfer for primary-side components and secondary side components contained within the SGs that are within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Steam Generators* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Steam Generators* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Steam Generators* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.11 Open-Cycle Cooling Water System

Program Description

The *Open-Cycle Cooling Water System* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that manages cracking, flow blockage, loss of material, and reduction of heat transfer for piping, piping components, and heat exchangers identified in the January 31, 1990 response to NRC Generic Letter 89-13 (GL 89-13)(ADAMS Accession No. ML20011E121) regarding the Recommended Actions in GL89-13. Implementation of the Recommended Actions was confirmed in a letter submitted on December 17, 1991 (ADAMS Accession No. ML20086P266). The program is comprised of the aging management aspects of the response to GL 89-13 and includes: (a) surveillance and control to reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer or efficiency of safety-related heat exchangers, and (c) routine inspections and maintenance so that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems cooled by the service water system. This program addresses operating experience (OE) that ensures aging effects continue to be adequately managed.

The service water system includes those components that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in GL 89-13. A fresh-water lake (Monticello Reservoir) is used for circulating water and make-up to the service water pond. The service water pond is designated as the ultimate heat sink.

Guidance provided in GL 89-13 is utilized for procedures which accomplish surveillance and control of biofouling for the service water system. Procedures provide instructions for chemical and biocide injections. Periodic sampling procedures monitor system concentrations of added chemicals. In addition, periodic flushing, cleaning and/or inspections are performed to detect the presence of biofouling. If biofouling is found, the condition is entered into the Corrective Action Program for further evaluation.

Periodic heat transfer testing, efficiency testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function are performed in accordance with the commitment in the docketed response to GL 89-13 to verify heat transfer capabilities.

Safety-related piping segments are periodically examined using visual and volumetric (UT) examinations to ensure there is no significant loss of material or cracking, which could cause a loss of intended function. Routine inspections and maintenance ensure corrosion, erosion, and biofouling do not degrade the performance of safety-related systems cooled by service water.

The *Buried and Underground Piping and Tanks* program (B2.1.28) manages the aging effects of external surfaces of buried and underground piping and components. The external surfaces of the above ground raw water piping and heat exchangers are managed by the *External Surfaces Monitoring of Mechanical Components* program (B2.1.23). Internal surface coatings are managed by the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.29).

NUREG-2191 Consistency

The *Open-Cycle Cooling Water System* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M20, "Open-Cycle Cooling Water System."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Scope of Program (Element 1)

1. A plant modification will be implemented to the safety-related portion of service water piping in the Service Water Pump House that provides cooling water to the cooling coils to eliminate concerns with recurring internal corrosion. Specifically, the modification will either isolate and drain or physically remove the aforementioned safety-related portion of service water piping.
2. A plant modification will be implemented to replace the carbon steel service water return valves from the diesel generator coolers with stainless steel valves and fittings to be more resistant to cavitation damage, and to modify the piping configuration to reduce cavitation.

Detection of Aging Effects (Element 4)

3. Procedure(s) will be revised to specify that inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task.

Corrective Actions (Element 7)

4. Procedure(s) will be revised to specify that additional inspections will be performed if any inspection results do not meet the acceptance criteria unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Open-Cycle Cooling Water System* program has been, and will be, effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2011, volumetric examinations were performed as part of the routine periodic measurements of wall thickness for piping in the service water system. Volumetric measurements for the HVAC chiller discharge line indicated that the projected wall thickness would be below the minimum allowable value by the Spring 2014 refueling outage (RF21). The probable cause of the wall thinning was identified as loss of material due to pitting corrosion. The piping was replaced with like material during the Fall 2012 refueling outage (RF20). Subsequent volumetric examinations performed at this location in the Fall 2015 (RF22) and the Spring 2020 (RF25) were satisfactory.
2. In February 2013, eddy current testing results for the 'A' diesel generator lube oil cooler indicated that one tube had exceeded the tube plugging criterion of 65% wall loss (interior). The loss of material was determined to be a result of MIC. The affected tube was plugged and the lube oil cooler was returned to service.
3. In March 2015, multiple tubes were found to be blocked by debris during the scheduled pre-cleaning inspection of the 'A' diesel generator intercooler. It was estimated that a total of 70 tubes were completely blocked (including previously plugged tubes), and an additional 41 tubes were partially blocked. The debris was subsequently removed during the cleaning of the intercooler. An existing thermal performance evaluation had determined that the intercooler would continue to provide adequate cooling with as many as 180 tubes plugged, so there was no operational concern about heat exchanger performance.
4. In January 2016, a small through-wall hole was identified on an elbow in the recirculation piping for the 'B' train service water booster pump. The hole was caused by cavitation damage due to the 45-degree elbow being located immediately downstream of a flow restricting orifice. Portions of the service water booster pump recirculation piping are included in the service water system wall thickness monitoring program. However, volumetric examinations were not being performed downstream of the flow restricting orifice. The damaged section of piping containing the elbow was replaced, and volumetric examinations at the downstream elbow were subsequently added to the program scope.
5. In March 2017, eddy current testing results for the 'A' diesel generator lube oil cooler indicated that five additional tubes had exceeded the tube plugging criterion due to pitting corrosion. The additional five tubes brought the total number of plugged tubes to eight. A design calculation was performed and the results concluded that the 'A' diesel generator lube oil cooler would continue to provide adequate cooling with as many as 61 plugged tubes. Therefore, it was determined that having eight plugged tubes would not prevent the 'A' diesel generator lube oil cooler from fulfilling its intended function.

6. In June 2018, a pinhole leak was discovered in the service water return piping downstream from the 'B' component cooling water heat exchanger. The pinhole leak was determined to be a result of loss of material due to cavitation. A butterfly valve used to throttle flow just upstream of the degraded area had caused the cavitation.

   A temporary modification was installed to encapsulate the degraded area until a permanent design change could be implemented during a future refueling outage.

   In 2020, a plant modification installed a new valve suited for throttling flow downstream of the 'B' component cooling water heat exchanger. Additionally, the modification installed a new flow straightening orifice upstream of the throttle valve. Due to susceptibility to cavitation degradation, the modification was also implemented for 'A' service water train in 2021.

7. In October 2018, during an engineering inspection, a diesel generator cooling system service water return valve was found to have cavitation degradation on the valve body. Weld repairs were performed per ASME Code, Section XI, requirements. Subsequent corrective action involved developing a plant modification to replace the carbon steel valves in both trains with stainless steel to be more resistant to cavitation damage, and modify the piping configuration to reduce cavitation.

8. In July 2020, degraded thermal performance resulting from fouling was discovered for a component cooling heat exchanger. The thermal performance was determined to be above the acceptance criterion, but less than the typical value. In response, guidelines were established for changes in the chemical injection strategy and thermal performance testing criteria. Based on the new guidelines, daily chemical injections of biocide and bio-dispersant were initiated for both trains of service water, and the thermal performance monitoring frequency was increased to monthly on each component cooling water heat exchanger. As the thermal performance improved, chemical injections were reduced from daily to three times per week per train. Thermal performance monitoring was returned to the regularly scheduled quarterly frequency when the thermal performance became consistent with values typically obtained following mechanical cleaning of the heat exchangers during outages.

   Recurring Internal Corrosion (RIC)

   A review of OE since 2011 indicates that recurring internal corrosion (RIC) has occurred in the service water system due to microbiologically influenced corrosion (MIC) for carbon steel exposed to raw water.

   Several through-wall leaks due to MIC occurred in sections of service water piping from 2011 through 2014. Corrective action involved replacing degraded sections of piping on an as-needed basis. Chemical treatment of the service water system using biocide and bio-dispersant occurred during the summer of 2012 but was intended only to reduce biological growth and fouling that were degrading heat exchanger thermal performance. Chemical treatment to address loss of material began in 2015 with the installation of a permanent chemical injection system and the use of additional chemicals. The current chemical treatment includes a macro-biocide, a micro-biocide, bio-dispersant, corrosion inhibitor, dispersant, and azole.

Several through-wall leaks, or wall thinning identified by planned volumetric examinations, have occurred due to MIC since 2012 in segments of service water piping that do not have continuous flow and do not regularly receive chemical treatment.

- Through-wall leaks have occurred from 2012 to 2018 in a section of service water piping to the service water pump house cooling coils. The cooling coils are not in service but the piping to the coils has not been abandoned and continues to contain stagnant service water without active exposure to chemical treatment. That section of pipe includes approximately 20 feet of 3-inch diameter carbon steel piping. As a corrective action for the leaks, piping replacements have been needed for several sections of piping up to 20 feet in length. As a longer-term corrective action, the safety-related service water piping that provides cooling water to the cooling coils will be permanently removed from service due to concerns with recurring internal corrosion.
- Wall thinning degradation due to MIC was identified during planned ultrasonic testing (UT) examinations in 2017 in the following two locations:
    a. Service water discharge piping from a reactor building cooling unit (RBCU). Since the RBCUs are normally cooled by industrial cooling water, service water does not flow in that line during normal operation, and the piping does not routinely receive chemical treatment to reduce the likelihood of MIC. Corrective action involved replacing two feet of degraded 16-inch diameter carbon steel with new carbon steel piping and the associated piping elbow.
    b. Service water backflush piping for a component cooling heat exchanger. Since service water flow in that segment of piping is not continuous, chemical treatment also is not continuous. Corrective action involved replacing approximately 1.5 feet of 20-inch diameter carbon steel with new carbon steel piping.

    A site procedure continues to direct periodic volumetric examinations of service water piping for indications of MIC-related degradation. Future indications of degradation identified during the inspections will be entered into the Corrective Action Program.
- MIC-induced wall thinning degradation was identified during planned UT examinations in 2018 in service water piping that provides screen wash for the 'A' traveling screen. The degraded section of carbon steel piping was replaced with nine feet of new carbon-steel piping and fitting. In 2021, planned UT examinations identified a MIC-induced leak in service water piping providing screen wash for the 'B' traveling screen. The leak occurred at the toe of a weld for an elbow. The leak was repaired using a weld buildup.

The service water in the supply piping for the traveling screen wash is stagnant most of the time since flow occurs for only approximately 30 minutes during each 12-hour interval thus reducing the effectiveness of the chemical treatment to mitigate occurrence of MIC. A site procedure continues to direct periodic volumetric examinations of service water piping for indications of MIC-related degradation. Future indications of degradation identified during the inspections will be entered into the Corrective Action Program.

The above examples of operating experience provide objective evidence that the *Open-Cycle Cooling Water System* program includes activities to perform visual and volumetric inspections, and heat transfer testing, to identify cracking, flow blockage, loss of material, and reduction of heat transfer for piping, piping components, and heat exchangers within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Open-Cycle Cooling Water System* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Open-Cycle Cooling Water System* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Open-Cycle Cooling Water System* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.12 Closed Treated Water Systems

Program Description

The *Closed Treated Water Systems* program is an existing condition monitoring and mitigation program that manages cracking, loss of material, and reduction of heat transfer. 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 so that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation. The program uses as applicable, EPRI Report 3002000590, “Closed Cooling Water Chemistry Guideline.” Microbiological testing is performed as a diagnostic chemistry parameter for selected system water treatments.

The *Closed Treated Water Systems* program activities are implemented through procedures. Mitigative activities include utilizing chromate-based, silicate-based, or nitrite-based chemistry controls to minimize the age-related degradation of components exposed to a closed treated water environment.

The performance of sample analyses assures water chemistry parameters are maintained within the goal ranges specified by procedures based on EPRI Report 3002000590. Monitoring of water chemistry parameters also assures contaminants are kept below applicable limits to minimize corrosion. Condition monitoring activities provide for periodic and opportunistic visual inspections whenever the system boundary is opened. A representative sample of components is selected based on the likelihood of loss of material, cracking, or reduction of heat transfer and inspected at an interval not to exceed once in ten years. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of 25 components per population will be inspected. At least 20% of the surface area will be inspected unless the component is measured in linear feet, such as piping. For piping, inspecting a one-foot axial length section is considered one inspection. Any combination of one-foot sections of piping and components can be used to meet the recommended extent of 25 inspections.

Inspections will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. Heat transfer capability of heat exchanger surfaces is evaluated by performing as-found visual inspections that assess surface cleanliness.

If any inspections do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required.

Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.

The additional inspections will include inspections of components with the same material, environment, and aging effect combination. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted. Inspections and tests will be 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 inspection procedures include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The *Closed Treated Water Systems* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Closed Treated Water Systems* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M21A, “Closed Treated Water Systems,” as modified by SLR-ISG-2021-02-MECHANICAL, "Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Detection of Aging Effects (Element 4)

1. Procedure(s) will be revised to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections be completed for the various sample populations (each material, water treatment program, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by

the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% 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 will be inspected. The inspections will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions.

2. Procedure(s) will be revised to specify inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task.

Monitoring and Trending (Element 5)

3. Procedure(s) will be revised to specify that, where practical, the rate of any degradation is evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.

Corrective Actions (Element 7)

4. Procedure(s) will be revised to specify that additional inspections will be performed if any inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Closed Treated Water Systems* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. On several occasions since February 2011 following maintenance activities, diesel generator jacket water cooling chemical analysis indicated out-of-specification results. For example, nitrite concentrations indicated OOS low in a range between 58.7 ppm and 192 ppm. The nitrite specification range is 500-1500 ppm. Several of the samples indicated azole

concentrations OOS low in a range between 1.5 ppm and 3.8 ppm. The azole specification range is 5-100 ppm. Two of the samples indicated pH OOS low at 7.92 and 8.43. The pH specification range is 8.5-11.0. The OOS conditions had been expected due to draining and refilling the diesel generator jacket water subsystem before and after maintenance activities. Each time, chemical additions were performed, the system was re-sampled, and the sample results indicated the parameters were restored within the specification ranges.

2. Between 05/11/2011 and 06/01/2011, analysis of the 'B' train component cooling water (CCW) sample results indicated that chloride concentration was trending upward. On 05/11/2011, chloride concentration was 100 ppb, on 05/28/2011 the concentration was 209 ppb, and on 06/01/2011 the concentration was 258 ppb. The increasing chloride concentration was attributed to several service water (SW) intrusions during RF19 while testing lube oil cooler swap overs from CCW to SW. Although the values were not out of specification (the limit for chloride in CCW is less than or equal to 1000 ppb) the sampling frequency for chloride, fluoride and sulfate contaminants in the CCW system was increased from monthly to weekly until new equilibrium levels were reached, indicating no further SW was entering the CCW system.
3. In November 2016, the 'A' and 'B' diesel generator jacket water subsystems were found to have azole concentration OOS low at 4.7 ppm and 3.7 ppm, respectively. The azole specification range is 5-100 ppm. Due to normal operations, sample purging, and makeup, there had been a slow decrease in azole concentration. Chemical addition and re-sampling were performed, and the as-left sample analysis results found azole concentration had returned to within the normal operating limits.
4. In December 2018, following a metasilicate addition, the industrial cooling water silica sample concentration was 15 ppm with a backup sample concentration of 14.4 ppm. The normal silicate concentration specification range is 35-75 ppm. Following the lower than expected sample result, two additional chemical additions were made to determine if the system was losing silicate concentration due to corrosion inhibitor demand or to system dilution. Following each chemical addition, sample analyses indicated concentrations dropping by half over a 24-hour period. Engineering determined that the cause of the leakage was system out-leakage as seat leakage from the reactor building cooling units (RBCUs) service water return isolation valves.

   Engineering developed a troubleshooting plan to inspect the downstream side of a RBCU service water return isolation valve via borescope. The borescope inspection revealed that the valve seat was allowing industrial cooling water to leak out into service water piping at approximately 30 gpm. Adjustment of the gate against the seat did not stop the leakage. A work order was initiated to inspect the valve seat and replace as necessary during RF25. The valve seating surfaces were cleaned, and the valve was returned to service in April 2020.

Subsequent analysis results of silica concentration stabilized, indicating the seat leakage was corrected.

The above examples of operating experience provide objective evidence that the *Closed Treated Water Systems* program includes chemistry control of system water and inspections of system internal surfaces to identify loss of material, cracking, and reduction of heat transfer for components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Closed Treated Water Systems* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Closed Treated Water Systems* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Closed Treated Water Systems* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.13 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 is an existing condition monitoring program that manages loss of material due to general corrosion and wear, deformed or cracked rails, bridges, structural members, and structural components; and loss of material due to general corrosion, cracking and loss of preload on bolted connections for cranes and hoists within the scope of subsequent license renewal. The inspection and maintenance activities specified in this program are consistent with the following requirements identified in FSAR Section 3.12.4.1:

- ANSI B30.2 1976, "Overhead and Gantry Cranes (Top Running Bridge, Multiple Girder)"
- NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants"

The cranes and hoists within the scope of subsequent license renewal include those previously evaluated as part of compliance with NUREG-0612, as well as other equipment handling systems operating over safety-related equipment. Also, within the scope of subsequent license renewal are fuel and equipment handling systems that handle loads over fuel and safety-related equipment.

The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program uses periodic visual inspections and non-destructive examination (NDE) examinations, as needed if identified during any follow-up under the Corrective Action Program, to manage cracking and loss of material. Structural bolting is also monitored for loss of preload by inspecting for loose or missing bolts, or nuts. Inspection frequencies are consistent with the recommendations within the ASME/ANSI B30 series of standards. For handling systems that are infrequently in service, such as those only used during refueling outages, periodic inspections are performed prior to use. Cranes and hoist inspections do not include inspection of the structures that support the cranes. The individual structures and structural components are examined by the *Structures Monitoring* program (B2.1.35).

NUREG-2191 Consistency

The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Scope of Program (Element 1); Parameters Monitored / Inspected (Element 3); Detection of Aging Effects (Element 4); and Acceptance Criteria (Element 6)

1. Procedure(s) will be revised to require:
   - Visual inspections of rails, bridges, structural members, and structural components for loss of material due to general corrosion; deformation; cracking, and wear.
   - Visual inspections of rails, bolted connections for loss of material due to general corrosion; cracking; and loose or missing bolts or nuts, and other conditions indicative of loss of preload.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2016, it was identified that the spent fuel pit bridge crane was generating foreign material along the rail as it moved through a section of its normal travel path adjacent to the spent fuel pool. Operation of the crane revealed that the foreign material was due to loss of material due to wear. The cause of the wear was attributed to misalignment of the guide rollers used to assist in maintaining the crane along the proper orientation. This misalignment resulted in contact between the rails and the seismic restraint brackets. New brackets were fabricated and installed for the guide rollers and the guide rollers were properly adjusted. The clearance between the seismic restraint brackets and the rails was increased to prevent grinding against the rail during operation. The results of subsequent inspections of the spent fuel pit bridge crane in 2019 and 2021 were satisfactory.
2. In May 2017, during the Reactor Building closeout inspection following a refueling outage, metal flakes were identified along the reactor building polar crane bridge and trolley rails. This condition was reviewed by the reactor building polar crane subject matter expert who determined that the small amount of metal flakes was a normal byproduct of metal-to-metal wear between the wheels and the rails and that no immediate corrective actions were required. The results of subsequent inspections of the reactor building polar crane in 2018 and 2020 were satisfactory.

The above examples of operating experience provide objective evidence that the *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program includes activities to perform visual inspections to identify loss of material due to general corrosion or wear of the rails, bridges, structural members, and structural components; and identify deformation or cracking of the rails, bridges, structural members, and structural components. In addition, bolted connections are monitored for loss of material, cracking, and loose bolts, missing or loose nuts, and other conditions indicative of loss of preload and to initiate corrective actions. Occurrences identified under the *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.14 Compressed Air Monitoring

Program Description

The *Compressed Air Monitoring* program is an existing preventive and condition monitoring program that manages loss of material. The *Compressed Air Monitoring* program includes monitoring of air moisture content and contaminants such that specified limits are maintained, and performance of opportunistic inspections of components for indications of loss of material.

This program is consistent with the response to NRC Generic Letter 88-14 (GL 88-14), “Instrument Air Supply Problems,” and INPO SOER 88-01, “Instrument Air System Failures”. The program relies on guidance and standards provided in EPRI TR-108147, “Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079,” and ANSI/ISA-S7.3-1975, “Quality Standard for Instrument Air,” for testing and monitoring air quality and moisture. The *Compressed Air Monitoring* program activities implement the moisture content and contaminant criteria of ANSI/ISA-S7.3-1975 (incorporated into ISA-S7.0.01-1996).

Program activities include air quality checks at various locations to ensure that dew point, particulates, and hydrocarbons are maintained within the specified limits. Opportunistic inspections of select compressed air system components internal surfaces for loss of material due to corrosion are performed. The effects of corrosion and presence of contaminants are detected during quarterly surveillance monitoring activities. The procedures and maintenance activities for these surveillances include specific inspection acceptance criteria. The opportunistic inspections of accessible internal surfaces of compressed air system components provide assurance that the associated systems within the scope of subsequent license renewal will perform their intended function.

Inspections and tests will be performed by personnel qualified in accordance with site procedures and programs to perform the specified task.

The monitoring methods are effective in detecting the applicable aging effects and prevent significant age-related degradation. Corrective actions are taken for results that do not satisfy established criteria or if corrosion is identified on internal surfaces.

NUREG-2191 Consistency

The *Compressed Air Monitoring* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M24, “Compressed Air Monitoring.”

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Detection of Aging Effects (Element 4); Monitoring and Trending (Element 5); and Corrective Actions (Element 7)

1. Procedure(s) will be revised to require Turbine Building instrument air dryer outlet dew point readings greater than zero be documented in the Corrective Action Program and evaluations performed for results that do not satisfy established criteria as identified in the applicable procedures.

Detection of Aging Effects (Element 4)

2. Procedure(s) will be revised to specify inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Compressed Air Monitoring* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In August 2011, it was noted that Reactor Building instrument air header pressure was cycling at a lower pressure with 'A' air dryer in service. After multiple attempts to disassemble and clean the associated moisture separator proved to be ineffective, a new moisture separator element was installed and the dryer was blown down. The dryer was returned to service and pressure readings indicated a successful corrective maintenance. An annual preventive maintenance task replaces the moisture separator element and conducts blowdown to remove any loose material or particulates from the dryers.
2. In November 2014, a dryer moisture separator was found full of water due to ineffective drain configuration and infrequent overhaul. Rust sediment inside the separator further contributed to lack of proper drainage. The moisture separator was replaced per vendor recommendation and satisfactorily returned to service.
3. In February 2017, rust was discovered inside an instrument air elbow fitting. The adjacent nylon tubing was also clogged with rust, preventing air flow and the moisture separator discharge check valve was found to have rust clogging it’s internals. After unclogging, the nylon tubing was replaced. The moisture separator discharge check valve was determined to be operable and was cleaned before re-installation. The instrument air/service air compressor 'A' discharge condensate strainer was removed for inspection and rust particulate was found. The strainer and housing were cleaned and reinstalled. The cause of this condition was determined to be a vendor design configuration flaw which was subsequently corrected.

4. In May 2018, no flow was noted downstream of instrument air/service air receiver tank drain trap bypass valve, and it was determined the bypass line was clogged with rust buildup. The associated instrument air piping, valve and unions were replaced with new piping and piping components.
5. In August 2018, system trending identified increased dew point temperatures in the instrument air system. Samples indicated instrument air dewpoints higher than previous readings, and dryer performance throughout the system had decreased. The increase in dewpoint temperature did not exceed procedural requirements. Instrument air moisture intrusion/control issues could be indicated by a negative trend. As such, further investigation of dryer operation was performed which indicated that moisture was being removed as expected. The dew point monitors used to obtain the apparent high dew point readings were determined to be failing and one monitor was replaced. Subsequently, data collected with the newly installed dew point monitor aligned with previous readings and the dewpoint spike was determined to be erroneous.
6. In December 2018, the instrument air sampling vendor contacted the instrument air system engineer to report their sampling kits were defective. According to the vendor, the membranes used for particulate were found to have a manufacturer defect that caused the sample to come back with a false reading of high and large particulate count. The vendor recommended that the most recent sample data, taken with the defective kits, be disregarded. Air quality samples from the past year (previous four air quality samples) showed no indication of a negative trend toward high/large particulate count in the instrument air or service air system.

The above examples of operating experience provide objective evidence that the *Compressed Air Monitoring* program includes activities to perform air quality checks at various locations to identify loss of material on the internal surfaces of compressed air system components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Compressed Air Monitoring* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Compressed Air Monitoring* program will effectively identify aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Compressed Air Monitoring* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.15 Fire Protection

Program Description

The *Fire Protection* program is an existing condition monitoring and performance monitoring program that requires periodic visual inspections of fire barrier components, and functional testing of fire-rated doors and the carbon dioxide (CO_2) fire suppression system. The program manages:

- Loss of material for fire-rated doors, fire damper housings, steel seismic gap covers, and the CO_2 fire suppression system
- Loss of material or cracking for concrete structures, including fire barrier walls, ceilings, and floors
- Shrinkage and loss of strength for elastomeric fire barrier penetration seals and for seismic gap elastomers
- Change in material properties, cracking/delamination, loss of material, and separation for non-elastomer fire barrier penetration seals, fire stops, radiant energy shields, and fire wraps and coatings

The *Fire Protection* program requires periodic visual inspections of the penetration seals, and the fire barrier walls, ceilings and floors in structures within the scope of subsequent license renewal. Periodic visual inspections of fire barriers include determining the condition of fire wraps, fire-rated doors, and fire damper housings. These periodic inspections are performed every 18 months.

For the penetration seals, a 10% sample of each seal type is visually inspected each refueling outage. If abnormal degradation is observed, an additional 10% sample population is inspected. The process for 10% sample population expansions continues until no abnormal degradation is observed.

The *Fire Protection* program monitors the external surfaces of the CO_2 fire suppression system components for aging effects during plant walkdowns. Visual inspections during the walkdowns identify corrosion that may lead to loss of material. Periodic functional testing is performed to confirm the operability of the CO_2 fire suppression system. The halon fire suppression system is used only for the Secondary Alarm Station and does not require aging management for SLR.

Personnel performing inspections are qualified and trained to perform the inspection activities. Unacceptable conditions are entered into the Corrective Action Program for disposition.

The *Fire Protection* program is a risk-informed, performance-based program built upon National Fire Protection Association (NFPA) 805, “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition”. Adoption of NFPA 805 in accordance with Title 10 of the Code of Federal Regulations (10 CFR) 50.48(c) serves as the method of satisfying 10 CFR 50.48(a) and General Design Criterion 3.

NUREG-2191 Consistency

The *Fire Protection* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M26, “Fire Protection,” as modified by SLR-ISG-2021-02-MECHANICAL, "Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements:

Parameters Monitored / Inspected (Element 3); Detection of Aging Effects (Element 4); and Acceptance Criteria (Element 6)

1. Procedure(s) will be revised to provide guidance for detection of loss of material, cracking, holes, and gaps during the visual inspections of fire dampers, and to determine the acceptability of the findings.

Monitoring and Trending (Element 5)

2. Procedure(s) will be revised to provide guidance to ensure that inspection results for fire protection components are trended to provide for timely detection of aging effects so that the appropriate corrective actions can be taken. Where practical, identified degradation will be projected until the next scheduled inspection. Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.

Corrective Actions (Element 7)

3. Procedure(s) will be revised to provide guidance for evaluating projected inspection results. For results that will fail to meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the Corrective Action Program.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fire Protection* program has been, and will be, effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In July 2014, a 1-inch diameter hole was identified on a gypsum fire barrier wall in the switchgear room. The hole penetrated the gypsum (fire barrier) but not the corrugated steel on the opposite side (pressure boundary). The pressure boundary was intact, but the fire barrier was degraded. The hole in the gypsum board was patched with joint compound to correct the condition and restore the function of the gypsum wall as a fire barrier.
2. In February 2015, during a plant walkdown, a fire barrier penetration seal was found to contain a void. The penetration was supposed to contain 10 inches of foam seal material. The degradation was 3-2/3 inches deep within the 10-inch foam, and was approximately 6 inches high. It appeared to be due to shrinkage rather than any external damage. The void in the penetration seal was filled with the required amount of additional foam sealant to correct the condition, and to restore the penetration seal as a fire barrier.
3. In March 2016, during scheduled inspections of fire barriers in the Control Building, it was identified that the Kaowool fire barrier for one of the penetrations was degraded due to a gap between the Kaowool triple wrap and the adjacent drywall. The gap was closed using RTV fire-resistant foam to reconnect the Kaowool triple wrap to the drywall, thus correcting the condition and restoring the fire barrier function.
4. In December 2016, an Intermediate Building door would not close and latch under its own power to perform its intended function. The door is a NFPA 805 rated fire barrier. The door closer was adjusted and the lockset was tightened to correct the condition and restore the function of the fire-rated door.
5. In July 2018, while performing planned fire barrier inspections in the Turbine Building, two 1/2-inch diameter holes were found on the exterior side of the east masonry wall. The holes did not fully penetrate through the wall. The wall is a NFPA 805 rated high safety significant fire barrier. Engineering evaluated the condition, and confirmed that grout repairs of the holes were needed to restore the fire barrier function for the masonry wall. The holes in the masonry wall were filled with grout to correct the condition and restore the masonry wall as a fire barrier.
6. In January 2019, during an inspection of fire barriers, degradation was identified at a penetration in the Intermediate Building. The foam/lead shielding material had separated from the top of the penetration along its full length. The separation appeared to be the result of additional curing of the foam/lead seal material over time. The separation in the penetration seal was filled with high density shielding foam to correct the condition and to restore the function of the penetration seal as a fire barrier.
7. In October 2019, during planned fire barrier inspections, it was observed that the Albi-Duraspray fire-proofing coating located at a structural column was separating from the column. The degradation was assessed by Engineering as cosmetic. The degraded Albi-Duraspray fire proofing was replaced with Pyrocrete-241 to correct the condition and restore the function of the fire proofing coating.

The above examples of operating experience provide objective evidence that the *Fire Protection* program includes activities to perform visual inspections to identify loss of material and cracking, loss of strength, and shrinkage for fire barriers, fire barrier penetrations, fire-rated doors, and fire dampers; and functional testing for fire-rated doors and CO_2 fire suppression system components within the scope of subsequent license renewal; and to initiate corrective actions. Occurrences identified under the *Fire Protection* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fire Protection* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Fire Protection* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.16 Fire Water System

Program Description

The *Fire Water System* program is an existing condition monitoring program that manages loss of material and flow blockage for in-scope water-based fire protection systems. This program manages aging by conducting periodic visual inspections, flow testing, and flushes performed in accordance with the 2011 Edition of National Fire Protection Association (NFPA) 25, “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems”. Testing and inspections are conducted on a refueling outage interval as allowed by NUREG-2191, Section XI.M27, Table XI.M27-1, “Fire Water System Inspection and Testing Recommendations”. Flow tests confirm the system is functional by verifying the capability of the system to deliver water to fire service systems at required pressures and flow rates. Visual inspections are capable of evaluating conditions of external surfaces and conditions of internal surfaces to identify loss of material, cracking, and/or fouling. There are no nozzle strainers, fire water storage tanks, or foam water sprinkler systems within the scope of subsequent license renewal. Gaskets and fire hoses are excluded from scope as not-long-lived consumables that are periodically replaced consistent with NUREG-2191, VII.G.

Sprinklers will either be replaced or representative samples will be submitted to a recognized laboratory for field service testing in accordance with NFPA 25. Subsequent replacement or field service testing of representative samples will occur at 10-year intervals. Sprinkler testing will be performed consistent with the 2011 Edition of NFPA 25, Section 5.3.1. Fire service sprinkler system in-service dates vary. However, 50 years of sprinkler system service life has been conservatively determined to occur in April 2029. Therefore, the required sprinkler testing or replacement will be completed by April 2029.

Augmented testing and inspections beyond those required by NUREG-2191, Section XI.M27, Table XI.M27-1 will be performed for 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. The augmented testing and inspections will be conducted on piping segments that cannot be drained or piping segments that allow water to collect.

The water-based fire service system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. A low-pressure condition is alarmed in the main control room by the auto start of the electric motor driven fire pump, followed by the start of the diesel-driven fire pump if the low-pressure condition continues to degrade. The status of the fire pumps is indicated in the main control room.

Piping wall thickness measurements will be conducted when internal visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed, and the source is detected and corrected.

Inspections and tests will be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Non-code inspections and tests follow procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

If a flow test (i.e., NFPA 25, 2011 Edition, Section 6.3.1) or a main drain test (i.e., NFPA 25, 2011 Edition, Section 13.2.5) does not meet the acceptance criteria due to current or projected degradation, additional tests are or will be conducted. The number of increased tests is determined in accordance with the Corrective Action Program; however, there are no fewer than two additional tests for each test that did not meet the acceptance criteria. The additional inspections will be completed within the interval (i.e., five years or annual/refueling) in which the original test was conducted. If subsequent tests do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests required.

To address instances of recurring internal corrosion due to microbiological influenced corrosion (MIC) or pitting on the internal surfaces of fire protection system steel piping, a long-range plan has been developed which includes replacement of above ground isolation valves with internally lined valves, replacement of heavily corroded piping, and performance of internal inspections and cleaning. In addition, Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping will be performed during each refueling cycle to detect changes in the pipe wall thickness. Thinned areas found during the LFET scan will be followed-up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, opportunistic internal visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance. The piping age, time on service, and susceptibility to corrosion will be considered in determining sample locations.

Aging of the external surfaces of buried and underground fire main piping is managed by the *Buried and Underground Piping and Tanks* program (B2.1.28).

Loss of coating or lining integrity of cast iron valve bodies with internal lining and loss of material or cracking of cementitious lined piping exposed to raw water are managed by the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.29).

NUREG-2191 Consistency

The *Fire Water System* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M27, “Fire Water System.”

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Parameters Monitored / Inspected (Element 3)

1. Procedure(s) will be revised to require follow-up volumetric wall thickness examinations be performed when surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition are identified during visual inspections.

Detection of Aging Effects (Element 4)

2. Procedure(s) will be revised to require sprinklers that have been in service for 75 years be replaced or representative samples from one or more sample areas be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing and repeated at 5-year intervals.
3. Procedure(s) will be revised for wet pipe sprinkler systems to include a one-time test of sprinklers that have been exposed to water. A sample of 3% or a maximum of ten sprinklers with no more than four sprinklers per structure will be tested. Testing will be based on a minimum time in service of fifty years and severity of operating conditions for each population.
4. Procedure(s) will be revised to perform annual main drain tests on standpipe systems with automatic water supplies in the scope of subsequent license renewal as required by NFPA-25 (2011 Edition), Chapter 13, Valves, Valve Components, and Trim.
5. Procedure(s) will be revised to require flow tests every 5 years at the hydraulically most remote hose connections of each zone of automatic standpipe systems within the scope of subsequent license renewal as required by NFPA-25 (2011 Edition), Section 6.3.1, Flow Tests.
6. Procedure(s) will be revised to require a main drain test be conducted annually at each water-based fire protection system riser to determine whether there has been any change in the condition of the water supply piping and control valves. Acceptance criteria will be based upon monitoring flowing pressures from test to test to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. If required, the Corrective Action Program will determine the cause and any necessary corrective action.

7. Procedure(s) will be revised to specify inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task.
8. Procedure(s) will be revised to provide inspection guidance related to lighting, distance and offset for non-ASME Code inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used.
9. Procedure(s) will be revised to perform the following augmented testing and inspections of 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. The augmented tests and inspections indicated below will be conducted on piping segments that cannot be drained or piping segments that allow water to collect.
    a. In each five-year interval, beginning five 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% of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect.

       If the results of a 100% internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary.
    b. In each five-year interval of the subsequent period of extended operation, 20% of the length of piping segments that cannot be drained or piping segments that allow water to collect will be subject to volumetric wall thickness inspections. Measurement points will be obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, MIC). The 20% of piping that is inspected in each five-year interval will be in different locations than previously inspected piping.

   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.

Detection of Aging Effects (Element 4); Monitoring and Trending (Element 5); Acceptance Criteria (Element 6)

10. Procedure(s) will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits.

Detection of Aging Effects (Element 4); Acceptance Criteria (Element 6); Corrective Actions (Element 7)

11. Procedure(s) will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow every five years. Follow-up volumetric examinations will be performed if internal visual inspections detect an unexpected level of degradation due to corrosion product deposition. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following:

    a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have internal visual inspections of piping by opening a flushing connection at the end of one main and removing a sprinkler toward the end of one branch line, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected.

    b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have internal visual inspections of piping by removing a sprinkler nozzle from the most remote branch line from the source of water that is not equipped with the inspector's test valve, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

    c. Deluge systems - deluge systems in scope for subsequent license renewal will have internal visual inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

Monitoring and Trending (Element 5)

12. Procedure(s) will be revised to require results of sampling-based inspections be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

Corrective Actions (Element 7)

13. Procedure(s) will be revised to require that if a flow test (i.e., NFPA 25 Section 6.3.1) or a main drain test (i.e., NFPA Section 13.2.5) does not meet acceptance criteria due to current or projected degradation (i.e., trending) additional tests are conducted. The number of increased tests will be determined in accordance with the Corrective Action Program; however, there will

be no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections will be completed within the interval (i.e., 5 years, annual/refueling) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of tests.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fire Water System* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In November 2011, a pinhole leak was discovered in a horizontal section of 1-1/2 inch pre-action sprinkler system piping located in the Auxiliary Building. The piping was replaced and a visual inspection of the removed section of pipe was performed by Engineering and Chemistry. The inspection identified a buildup of silt and corrosion products to a depth of approximately ¼ inch in the bottom section of the pipe. In addition to replacing the piping, the system was flushed in May 2013. The probable cause of the pinhole leak was identified as localized corrosion under the silt buildup in the presence of moisture that had collected in the low point of the pipe. There was no appreciable wall thinning other than at the leakage point. The localized corrosion occurred in normally wetted piping and in piping sections normally pressurized with air but not fully drained.
2. On March 25, 2013, NRC Information Notice 13-06 (IN 13-06), "Corrosion in Fire Protection Piping due to Air and Water Interaction," was issued. The purpose of IN 13-06 was to alert licensees to operating experience involving the loss of function of fire protection sprinkler systems due to corrosion resulting from air-water interactions. Specifically, in sprinkler systems not designed and installed to allow complete drainage of the system following flow testing or system actuation, piping left partially filled with water and air was subject to accelerated internal corrosion. As a result of the internal corrosion, the increased corrosion product resulted in flow blockages of system piping. As identified in IN 13-06, Section 14.2 of NFPA 25 (2011 edition) requires an internal obstruction inspection of piping to be conducted every 5 years. This operating experience was evaluated by Engineering. As indicated in the evaluation, a fire service system corrosion monitoring program procedure was developed and issued to address corrosion due to air and water interaction. In accordance with the new procedure, Engineering inspects any fire service pipe which is opened for maintenance or other causes to look for signs of degradation, and non-destructive pipe thickness measurements are obtained on a periodic basis to trend degradation over time. Flow testing is performed every three years to verify system flow is not degrading.

3. In November 2013, the site reviewed the updated and approved September 2013 NEIL Loss Control Standards. As a result of the review, preventive maintenance tasks were created for inspecting and cleaning strainers (e.g., main line strainers) on a 5-year frequency consistent with the Loss Control Standards and NFPA 25 guidance. From February 2019 through May 2021, inspections were completed for strainers having a filtration intended function for subsequent license renewal. The inspections were satisfactory with no appreciable degradation identified.
4. In May 2021, ultrasonic testing (UT) was performed on sections of fire service above ground supply piping. Three UT readings were taken within each quadrant of the pipe circumference. Analysis was performed to determine the average yearly pipe wall losses and using that value to estimate the number of years until the minimum allowed wall thickness would be reached. The lowest reading from the quadrants in each pipe section was used to determine an average yearly pipe loss at each location. The year 1980 was conservatively selected as the original in-service date, per construction records for sprinkler piping testing. The estimated years until pipe replacement exceeded 80 years for the locations tested. Continued ultrasonic testing for these sections of piping are conducted at 10-year intervals.
5. Between January and April 2021, a representative sample of fire service sprinkler heads were removed and tested in support of a commitment for completing testing/replacement of sprinklers at year 50 of installed sprinkler life per NFPA 25. A representative sample of six sprinkler heads were replaced and four of the sprinkler heads were sent to Underwriters Laboratory for sensitivity and functional testing. The four sprinkler heads passed the testing. No replacements in the SWPH sample area were required.
6. In February 2022, the annual inspection was performed by divers in the fire pump bays. This included inspection of the suction strainers at the inlet of both fire pumps. The results of the inspection were satisfactory showing no appreciable flow blockage or loss of material.

<u>Recurring Internal Corrosion</u>

Since November 2011, more than 20 pinhole leaks have occurred in fire service piping. The pinhole leaks occurred in each successive outage cycle and thus meets the recurring internal corrosion definition.

Recurring internal corrosion is addressed by the *Fire Water System* program as follows:

- A long-range plan has been developed which includes replacement of above ground isolation valves with internally lined valves, replacement of heavily corroded piping, and performance of internal inspections and cleaning. Various sections of degraded fire service piping have been replaced in the Auxiliary Building and Intermediate Building. Results from most recent flow testing show increased flow rates through piping segments which have been partially replaced.
- Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping will be performed during each refueling cycle to detect changes in the pipe wall thickness. Thinned areas found during the LFET scan will be followed-up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits.
- Periodic fire service system piping flushes, flow testing and piping thickness measurements will be performed to identify pipe degradation prior to loss of system intended function.
- Internal visual inspections of system piping are performed opportunistically during cleaning or maintenance activities.
- Ultrasonic inspections are performed on fire service system piping with inspection sites chosen based on past results. If past results are not available, then preference is given to points most likely to experience corrosion such as low/no flow locations or locations subject to periodic filling and draining. Inspection results are evaluated by calculating a corrosion rate, which is used to determine whether the piping will last until the next inspection.

The above examples of operating experience provide objective evidence that the *Fire Water System* program includes activities to perform periodic inspections and flow tests to identify flow blockage and loss of material for in-scope water-based fire service systems within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fire Water System* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fire Water System* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Fire Water System* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.17 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is a new condition monitoring program that will manage cracking and loss of material on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil with internal pressures approximating atmospheric pressure. The program will manage aging effects for the following tanks:

- Condensate storage tank (CST)
- Reactor makeup water storage tank (RMWST)
- Refueling water storage tank (RWST)
- Sodium hydroxide storage tank (SHST)

The CST is located outside and rests on a four-foot concrete mat foundation covered with an approximately one and a half to two feet thick dry sand cushion. The RMWST, RWST, and SHST are located outside in a reinforced concrete pit. The RMWST and SHST rest on a concrete foundation. The RWST rests on a concrete foundation that is covered with a dry sand cushion.

For the CST, RMWST, and RWST, sealant or caulking is applied at the interface between the tank external surface and concrete to minimize the amount of water and moisture penetrating the interface. The SHST rests on a one-inch layer of grout with sides sloping away from the tank. This configuration minimizes the amount of water and moisture penetrating the interface by preventing water from accumulating.

The CST and SHST are fabricated from carbon steel and the external surfaces are primed and painted.

The RWST and RMWST are fabricated from stainless-steel and have fiberglass insulation on the top and sides, with an embossed aluminum jacket for protection.

The program will manage cracking and loss of material by conducting periodic external visual and surface examinations. Inspections of sealant are supplemented with physical manipulation. It has been demonstrated that the in-scope stainless steel tanks are not susceptible to SCC or loss of material (See further evaluation in Sections 3.2.2.2.2, 3.2.2.2.4, 3.3.2.2.3 and 3.3.2.2.4). Therefore, inspections of the internal and external surfaces of stainless-steel tanks will be performed by the *One-Time Inspection* program (B2.1.20). Thickness measurements of the tank bottoms will be conducted to detect degradation prior to loss of intended function. For the CST internal surfaces, loss of material and loss of coating integrity will be managed by the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.29).

Inspections not conducted in accordance with ASME Code, Section XI requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

NUREG-2191 Consistency

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks."

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Outdoor and Large Atmospheric Metallic Storage Tanks* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2017, during internal inspections of the CST for initial license renewal, ultrasonic testing was performed on the tank bottom. Obtained thickness measurements were deemed satisfactory with very consistent thicknesses across the measured location surfaces.
2. In October 2018 the RWST tank bottom, nozzles, sides (including the air to water interface), and roof were internally visually inspected for the loss of material. The inspection results were deemed satisfactory.
3. In February 2020, an external visual inspection of the RMWST was performed to identify wet insulation that could be indicative of tank leakage. The inspection results were satisfactory with no noted leakage or insulation degradation.
4. In May 2021, a volumetric examination was performed on the SHST at several tank wall locations including several locations near the tank bottom. The various thickness measurements indicated that the wall thickness values were above the nominal design wall thickness. Engineering reviewed the results and confirmed the thickness values were satisfactory.
5. In June 2021, an internal EVT-1 remote visual inspection of the RMWST was conducted to inspect for cracks or loss of material. Engineering reviewed the results from the remote visual examination and no indications of degradation were identified.

The above examples of operating experience provide objective evidence that the *Outdoor and Large Atmospheric Metallic Storage Tanks* program will include activities to perform visual inspections of tank internal bare metal surfaces, surface examination of external tank surfaces, and UT examinations of tank bottoms to identify cracking or loss of material for aboveground metallic tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Outdoor and Large Atmospheric Metallic Storage Tanks* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Outdoor and Large Atmospheric Metallic Storage Tanks* program will effectively identify aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Outdoor and Large Atmospheric Metallic Storage Tanks* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.18 Fuel Oil Chemistry

Program Description

The *Fuel Oil Chemistry* program is an existing mitigative, condition monitoring and preventive program that manages loss of material of tanks, piping, and components in a fuel oil environment. The program includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of subsequent license renewal.

The fuel oil tanks within the scope of subsequent license renewal include:

- Diesel driven fire pump fuel oil day tank
- Diesel generator fuel oil day tanks
- Diesel generator fuel oil storage tanks

The fuel oil storage tanks within the scope of subsequent license renewal do not have internal coatings or linings.

The fuel oil tanks within the scope of subsequent license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with Technical Specifications, Fire Protection Program Surveillances and Compensatory Measures and ASTM standards. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil.

The program samples and tests fuel oil using the guidelines of the following ASTM standards:

- ASTM D 975-81, “Standard Specification for Diesel Fuel Oils”
- ASTM D 1796, “Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure)”
- ASTM D 2276-88, “Standard Test Method for Particulate Contaminant in Aviation Fuel”
- ASTM D 4057-81, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products”

Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining/cleaning of tanks and by verifying the quality of new fuel oil before its introduction into the storage tanks. Where internal cleaning and inspection are not physically possible, bottom thickness measurements of inaccessible tanks will be performed in lieu of cleaning and internal inspection.

Corrective actions require water to be removed from fuel oil storage tanks when detected and the condition entered in the Corrective Action Program. Additionally, corrective actions, such as the addition of a biocide, are taken when the presence of biological activity is confirmed.

The *One-Time Inspection* program (B2.1.20) will be used to verify the effectiveness of the *Fuel Oil Chemistry* program for piping and piping components exposed to fuel oil.

The *Fuel Oil Chemistry* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Fuel Oil Chemistry* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M30, “Fuel Oil Chemistry.”

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Preventive Actions (Element 2); Parameters Monitored / Inspected (Element 3); Detection of Aging Effects (Element 4); Monitoring and Trending (Element 5); and Acceptance Criteria (Element 6)

1. Procedure(s) will be revised to drain, clean internally to the extent practical, visually inspect internal surfaces (if physically possible), and perform tank bottom thickness measurements for the following tanks:

    a. Diesel driven fire pump fuel oil day tank

    b. Diesel generator fuel oil day tanks

    c. Diesel generator fuel oil storage tanks

    The procedure(s) will require that if evidence of degradation is observed during visual inspection, or if visual inspection is not possible, volumetric inspections will be performed. The draining, cleaning and inspection of each tank will be performed at least once during the 10-year period prior to the subsequent period of extended operation and at least once every 10 years during the subsequent period of extended operation.

2. Procedure(s) will be revised to require an Engineering evaluation be performed to evaluate and trend visual and volumetric (if degradation is detected during inspections) tank inspection results. Unacceptable inspection results will be documented in the Corrective Action Program. Thickness measurements will be evaluated against the design thickness and corrosion

allowance. The rate of degradation will be evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection frequency will be adjusted, as necessary, based on the projection.

Preventive Actions (Element 2)

3. Procedure(s) will be revised to periodically drain accumulated water from the diesel driven fire pump fuel oil day tank.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fuel Oil Chemistry* program has been, and will be, effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In December 2013, during the monthly sampling of 'A' diesel generator fuel oil storage tank, the bottom sample had particulate contamination of approximately 5.42 ppm which is above the normal expected range of 1-2 ppm but below the Technical Specification 10 ppm limit (10 mg/L). In addition, the color of the water was purple which indicates possible water contamination. The samples taken at 5%, 20%, 50% and 80% levels were the normal red color. An evaluation determined the probable cause of the event was that fuel oil in the portable fuel oil trailer had a high particulate count and was of a higher density than normal off-the-road diesel fuel oil. The next monthly sample of diesel generator fuel oil storage tank 'A' in January 2014 had a normal particulate contamination level of 1.43 ppm and had normal color.
2. In June 2015, during the monthly sampling of 'A' diesel generator fuel oil storage tank, the water draw-off was identified to be cloudy/hazy. A follow-on draw-off verified the same appearance. Further investigation determined the cloudiness was attributed to water that was entrained in the oil and the water concentration was 0.55%. The sample obtained for particle contamination testing was a combination of samples taken from the 20%, 50%, and 80% tank levels of the tank with no indication of haziness or water. The sample was tested for particulates and the results were 0.13 ppm which is well below the acceptable limit of 10 ppm (10 mg/L). Another sample was obtained from the 5% level of the tank with no indication of haziness or water. A plan was developed to flush approximately 20 gallons of oil or until the sample was clear to remove any water contamination. After flushing approximately 25 gallons of oil, samples were obtained from the 5% and 80% tank levels and were compared for clarity with both being clear. The most probable cause for the water in the fuel oil was determined by Engineering to be condensation in the oil in the portable diesel fuel oil trailer used to top off the tanks. The next monthly sample obtained on July 21, 2015 was satisfactory.

3. In December 2015, a diesel fuel oil delivery failed clear and bright analysis on three of five tanker compartments. Chemistry procedures require sampling and testing of new fuel oil being delivered to the station prior to unloading into the auxiliary boiler fuel oil storage tank. The samples must be analyzed for flash point, viscosity, specific gravity and pass the clear and bright test. The clear and bright test is a non-quantitative test performed at the time of tank sampling and provides an initial indication the fuel contains no visible water drops or particulates. The trailer was not allowed to offload the fuel into the auxiliary boiler fuel oil storage tank and was returned to the vendor.
4. In July 2017, during monthly sampling of 'A' diesel generator fuel oil storage tank, less than 3 ml of water was indicated in the draw-off sample. Another draw-off sample was collected and there was no indication of water, which is an indication that accumulated water was removed from the tank prior to performing multilevel sampling.
5. In March 2020, internal inspections were performed on both 'A' and 'B' diesel generator fuel oil storage tanks in support of initial license renewal and the Underground Piping and Tanks Integrity Program (UPTIP). Inspections included visual inspections performed by a vendor following American Petroleum Institute (API) guidance in API-653, "Tank Inspection, Repair, Alteration, and Reconstruction," and wall thickness examinations performed by Quality Control. For each tank, UT readings were taken at 1178 locations around the circumference and length of two shell sections. No wall thickness readings were taken on the heads. The lowest thickness readings were 0.370 inch for 'A' tank and 0.352 inch for 'B' tank. There were signs of pitting at the bottom of both tanks. Based on pit gauge readings taken at the worst locations, the deepest pit was 3/64 inch for the 'A' tank. An additional UT reading was taken at the 3/64 inch pit location in the 'A' tank which showed a 0.323 inch wall thickness. Considering the nominal design wall thickness of 0.375 inch and the design corrosion allowance of 0.0625 inch, the readings were above the design minimum wall thickness of 0.3125 inch (i.e., 0.375 inch - 0.0625 inch). Options to mitigate degradation at the bottom of 'A' and 'B' diesel generator fuel oil storage tanks are currently being considered.

The above examples of operating experience provide objective evidence that the *Fuel Oil Chemistry* program includes activities to perform control of chemistry parameters to manage loss of material and to perform visual inspection of tanks to identify loss of material for fuel oil tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fuel Oil Chemistry* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fuel Oil*

Chemistry program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Fuel Oil Chemistry* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.19 Reactor Vessel Material Surveillance

Program Description

The *Reactor Vessel Material Surveillance* program is an existing condition monitoring program that manages reduction of fracture toughness of the ferritic reactor vessel (RV) beltline materials, in accordance with the edition of American Society for Testing Materials (ASTM), Standard E 185 available and used during fabrication of the RV. The program provides sufficient material to monitor reduction of fracture toughness due to neutron irradiation embrittlement until the end of the subsequent period of extended operation and determine any need for operating restrictions on the irradiation temperature (i.e., cold leg operating temperature), neutron spectrum, and neutron fluence.

The *Reactor Vessel Material Surveillance* program was developed by Westinghouse Electric Corporation prior to 10 CFR 50, Appendix H. The *Reactor Vessel Material Surveillance* program consists of two elements. The first element is related to the number of capsules, location of capsules, and content of specimens. The second element is related to the test methods and schedule for testing. Documentation for the first element, related to the design of the program, was provided in WCAP-9234, “South Carolina Electric and Gas Company, Virgil C. Summer Nuclear Plant, Unit No. 1, Reactor Vessel Radiation Surveillance Program,” and met ASTM E 185-73. The requirements relating to the testing method were not initially mandated by the NRC through a particular edition of ASTM E 185. As such, it was customary at the time to document the edition of ASTM E 185 used for testing when a capsule was removed from the RV. Over time, the NRC began approving various editions of ASTM E 185 for testing. To date, three editions of ASTM E 185 (-73, -79, and -82) have been approved by the NRC for testing and schedule considerations. The *Reactor Vessel Material Surveillance* program complies with ASTM E 185-82 for testing and scheduling. 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 ensure appropriate monitoring during the subsequent period of extended operation. The *Reactor Vessel Material Surveillance* program includes removal and testing of at least one capsule, with a neutron fluence between one and two times the projected peak RV neutron fluence at the end of the subsequent period of extended operation. If a capsule meeting this criterion has not been tested previously, then the program ensures at least one capsule will be removed and tested during the subsequent period of extended operation (or earlier) to meet this criterion.

Data from the *Reactor Vessel Material Surveillance* program is used to monitor neutron irradiation embrittlement of the RV and provided as input to the neutron embrittlement time limited aging analyses described in Section 4.2.

In accordance with 10 CFR 50, Appendix H, surveillance capsules, including those previously removed from the RV, 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 *Reactor Vessel Material Surveillance* program, or extension of the program for the subsequent period of extended operation, are required to be submitted to the Nuclear Regulatory Commission for approval prior to implementation, in accordance with the requirements of 10 CFR 50, Appendix H, Paragraph III.B.3. Standby capsules placed in storage (e.g., removed from the RV) are maintained for possible future insertion. If one or more capsules will not be maintained in such a way as to permit future insertion, then the NRC will be notified of the change.

Prior to plant start up, six RV capsules, more than the minimum recommended by ASTM E 185-73 or ASTM E 185-82, were installed in the RV. The six capsules, each containing representative RV material specimens, neutron dosimeters, and thermal monitors, have been removed from the RV. Five capsules (U, V, X, W, and Z) were tested after being withdrawn. Capsule Y, the only remaining untested capsule, was pulled at 17.71 EFPY with a fluence of 7.01 x 10^{19} n/cm^2. The five capsules already tested satisfy the regulatory requirements for the 60-year initial period of extended operation. The 80-year recommendations of NUREG-2191 specify that one capsule should be withdrawn at an outage with a neutron fluence of between one and two times the projected peak RV wall neutron fluence at the end of the subsequent period of extended operation and tested in accordance with the requirements of ASTM E 185-82. Thus, a schedule change is being pursued since Capsule Y does not meet the 80-year recommendations. The proposed schedule change () satisfies the regulatory requirements of the *Reactor Vessel Material Surveillance* program for 80 years of operation.

At the end of the 80-year subsequent period of extended operation (72 EFPY), one times peak RV wall neutron fluence is projected to be 9.06 x 10^{19} n/cm^2 (which includes a 10% bias on the peripheral and re-entrant corner assembly relative powers). Two times the peak RV wall neutron fluence at the end of the subsequent period of extended operation is projected to be 1.73 x 10^{20} n/cm^2 (2 x 8.64 x 10^{19} n/cm^2, which conservatively excludes the 10% bias). Therefore, the capsule withdrawn to meet the NUREG-2191 recommendations for 80 years of operation must reach a fluence above 9.06 x 10^{19} n/cm^2 and below 1.73 x 10^{20} n/cm^2. Since Capsule Y does not meet the NUREG-2191 requirements for fluence cited above it will be re-inserted for additional fluence accumulation and tested during the subsequent period of extended operation.

To meet the minimum of one times the projected peak RV wall neutron fluence at the end of subsequent period of extended operation recommended by NUREG-2191, Capsule Y should be exposed to at least 4.9 more EFPY of operation. Additionally, to remain below two times the projected peak RV wall neutron fluence at the end of subsequent period of extended operation recommended by NUREG-2191, Capsule Y should be withdrawn before 22.4 EFPY of additional irradiation. Since the minimum 100-year fluence is within the allowable range of one to two times the 80-year fluence, Capsule Y will be withdrawn after being exposed to a minimum of 10.5 more EFPY of operation in order to experience the minimum 100-year fluence of 1.14 x 10^{20} n/cm^2.

Assuming that Capsule Y is reinserted during the Fall 2027 (RF30) refueling outage, (the final opportunity to reinsert the capsule), and an average fuel cycle length of 1.33 EFPY/cycle, i.e., ~90% capacity factor, Capsule Y will need 8 cycles to achieve an additional 10.5 EFPY of irradiation (10.5 EFPY) / (1.33 EFPY/cycle), which means the removal of Capsule Y in the Fall 2039 (RF38) refueling outage. Since the plant has experienced 32.38 EFPY at the end of operating cycle 26, Capsule Y will be reinserted at 37.7 EFPY and removed after 48.2 EFPY (note: the RF38 projected EFPY is 48.4 EFPY). These dates are only intended to be an estimate. Commitments should be based on withdrawing Capsule Y at the outage nearest to, but following, the capsule fluence achieving the 100-year fluence, which is estimated to be after exposure to an additional 10.5 EFPY of irradiation. Capsule Y will be re-inserted into the 107° location (or symmetric locations 287° or 343°).

The proposed Surveillance Capsule Withdrawal Schedules are depicted in , provided at the end of this section.

An Ex-Vessel Neutron Dosimetry Program was established in 2005 to provide continuous monitoring of the neutron exposure of the beltline portion of the RV. The data obtained from the Ex-Vessel Neutron Dosimetry Program, coupled with measurements from in-vessel surveillance capsules enable an accurate evaluation of the best estimate RV neutron exposure (and associated uncertainty) over the service life of the unit. The ex-vessel neutron dosimetry is described in aging management program X.M2, “Neutron Fluence Monitoring.”

As part of operating experience, consistent with statements in NRC Regulatory Guide (RG) 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” the use of surveillance data from other sources is considered when they become available. As such, information from surveillance capsules withdrawn from a sister plant (Shearon Harris) vessel is used to supplement information from the *Reactor Vessel Material Surveillance* program subject to the credibility limitations stated in Regulatory Positions 2.1 and 2.2 of RG 1.99, Revision 2.

The *Reactor Vessel Material Surveillance* program is also used in conjunction with the *Neutron Fluence Monitoring* program (B3.2) which monitors neutron fluence for RV components and RV internal components.

The *Reactor Vessel Material Surveillance* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Reactor Vessel Material Surveillance* program is an existing program that is consistent with NUREG-2191, Section XI.M31, “Reactor Vessel Material Surveillance.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Reactor Vessel Material Surveillance* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In August 2004, Westinghouse issued WCAP-16298-NP, “Analysis of Capsule Z from the South Carolina Electric & Gas Company V. C. Summer Reactor Vessel Radiation Surveillance Program.” Capsule Z was removed at 16.36 EFPY and post-irradiation mechanical tests of the Charpy V-notch and tensile specimens were performed. A fluence evaluation utilizing the latest available neutron transport and dosimetry cross-section libraries was derived from the ENDF/B-VI database. Based on the results from the fluence evaluation, Capsule Z had received a fluence of 6.54×10^{19} n/cm^2 after irradiation to 16.36 EFPY. The peak clad/base metal interface vessel fluence after 16.36 EFPY of operation was determined to be 2.05×10^{19} n/cm^2. Capsule removal and testing utilized the guidance of ASTM E 185-82 and NUREG-2191.
2. In January 2016, NRC Information Notice 16-02 (IN 16-02), “Improper Seating of Reactor Vessel Surveillance Capsules,” was issued. IN 16-02 informed licensees of recent operating experience related to RV surveillance capsules that were not properly seated in their baskets and subsequently broke loose during plant operation. This resulted in the generation of over 200 loose parts in reactor vessels that adversely affected some in-vessel components. Subsequently, Westinghouse issued Technical Bulletin TB-16-5, “Irradiated Reactor Surveillance Capsule Seating Issue,” on August 17, 2016, to provide information regarding IN 16-02. The guidance in Technical Bulletin TB-16-5 was incorporated into station procedures. No loose parts due to improperly seated capsules were detected at VCSNS.

The above examples of operating experience provide objective evidence that the *Reactor Vessel Material Surveillance* program includes activities to perform withdrawal and testing of capsule specimens to manage a reduction in fracture toughness due to irradiation of the ferritic RV beltline materials, and to initiate corrective actions. Occurrences identified under the *Reactor Vessel Material Surveillance* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Appropriate guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. As a result, there is reasonable assurance that the continued implementation of the *Reactor Vessel Material Surveillance* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Reactor Vessel Material Surveillance* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

Table B2.1.19-1
VCSNS Unit 1 Surveillance Capsule Withdrawal Schedule

Capsule	Location (deg)	Capsule Lead Factor	Removal Time[(a)] (EFPY)	Capsule Fluence (n/cm^2, E > 1.0 MeV)[(b)]
U	343	3.04	1.13 (EOC 1)	6.75×10^{18}
V	107	3.34	2.93 (EOC 3)	1.54×10^{19}
X	287	3.54	5.04 (EOC 5)	2.51×10^{19}
W	110	3.21	11.21 (EOC 10)	4.63×10^{19}
Z	340	3.10	16.36 (EOC 14)	6.53×10^{19}
Y[(c)]	290	3.09	17.71 (EOC 15)	7.01×10^{19}
	107[(c)]	~3.5	48.2[(c)]	1.14×10^{20}

Notes:

a. Effective full power years from plant startup. End of Cycle (EOC) value given in parenthesis. Note that core thermal power was uprated from 2775 to 2900 MWt starting with operating Cycle 10.

b. Fluence values were taken from WCAP–18728–NP, Table 2–1.

c. Capsule Y will be reinserted during the Fall 2027 (RF30) refueling outage into location 107° (or symmetric locations 287° or 343°), which is projected to occur at 37.7 EFPY. Capsule Y will achieve the peak 100-year fluence, 1.14×10^{20} n/cm^2 (E > 1.0 MeV), before removal, which is calculated to require another 10.5 EFPY of operation (37.7 + 10.5 = 48.2).

B2.1.20 One-Time Inspection

Program Description

The *One-Time Inspection* program is a new condition monitoring program that will manage cracking, long-term loss of material, loss of material, and reduction of heat transfer of components exposed to air, condensation, fuel oil, lubricating oil, raw water, steam, treated borated water, treated water, underground, or waste water environments.

The *One-Time Inspection* program will conduct one-time inspections of susceptible locations to verify the effectiveness of the *Water Chemistry* program (B2.1.2), the *Fuel Oil Chemistry* program (B2.1.18), and *Lubricating Oil Analysis* program (B2.1.26). For steel components exposed to environments that do not include corrosion inhibitors, the *One-Time Inspection* program will verify that long-term loss of material will not result in a loss of intended function by performing wall thickness measurements on a representative sample of components in each environment.

The program will identify inspection locations that are isolated from the flow stream, that are stagnant, or have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. A representative sample size of 20% of the population (up to a maximum of 25 component inspections) will be established for each material, environment, and aging effect combination and will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions.

The program will verify either no unacceptable age-related degradation is occurring or trigger additional actions that will assure the intended function of affected components will be maintained during the subsequent period of extended operation. Technical justification of the methodology and sample size used for selecting components for one-time inspection will be documented in the One-Time Inspection Sample Basis Document.

This program will not be used for 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 will be conducted in those cases.

If any inspections do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.

The elements of the *One-Time Inspection* program will include: (a) determination of sample size for the components to be inspected based on an assessment of material, environment, 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 monitoring methods will be effective in detecting the applicable aging effects and the frequency of monitoring will be adequate to prevent significant age-related degradation.

Inspections and tests will be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. ASME Code components and non-ASME Code components will be inspected using procedures consistent with the ASME Code. Inspections not conducted in accordance with ASME Code, Section XI requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

The program will perform inspections of the refueling water storage tank, reactor makeup water storage tank, and sodium hydroxide storage tank consistent with NUREG-2191, Table XI.M29-1, “Tank Inspection Recommendations.”

The *One-Time Inspection* program will perform sample inspections for stainless steel, nickel alloy, and aluminum alloy components exposed to any air or condensation environment prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The *One-Time Inspection* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.M32, “One-Time Inspection.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following example of operating experience provides objective evidence that the *One-Time Inspection* program will be effective in managing the aging effects for systems, structures, and components (SSCs) within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2021, an evaluation was performed on the Chemistry Program one-time inspection results that were documented for initial license renewal from 2017 to 2021. Initial license renewal required one-time inspections in low flow areas of various treated water systems to demonstrate the effectiveness of the Chemistry Program for various material/environment combinations. The evaluation was to ensure that a representative sample of in-scope component groups had been inspected and to determine the need for supplemental inspections. The evaluation concluded that a representative sample of in-scope components had been inspected, and based on the results of the one-time inspections, that additional aging management is not required during the period of extended operation for the Chemistry Program.

The above example of operating experience provides objective evidence that the *One-Time Inspection* program will include activities to perform visual inspections to identify cracking, long-term loss of material, loss of material, and reduction of heat transfer of components exposed to air, condensation, fuel oil, lubricating oil, raw water, steam, treated borated water, treated water, underground, or waste water environments within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *One-Time Inspection* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *One-Time Inspection* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *One-Time Inspection* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.21 Selective Leaching

Program Description

The *Selective Leaching* program is a new condition monitoring program that will manage loss of material of the susceptible materials located in a potentially aggressive environment. The materials of construction for these components may include gray cast iron, ductile iron, and copper alloys (greater than 15% zinc).

A one-time inspection of components exposed to closed-cycle cooling water or treated water environments will be conducted when plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for raw water, waste water, soil, and groundwater environments, and for closed-cycle cooling water or treated water environments when plant-specific operating experience has revealed selective leaching in these environments. A sample of 3% of the population or a maximum of 10 components per population will be visually and mechanically (gray cast iron and ductile iron components) inspected. If the periodic inspection conducted for ductile iron in the 10-year period prior to the subsequent period of extended operation (i.e., the initial inspection) meets acceptance criteria, periodic inspections do not need to be conducted during the subsequent period of extended operation for ductile iron.

Periodic destructive examinations of components for physical properties (i.e., degree of dealloying, through-wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste water, soil, and groundwater environments or for closed-cycle cooling water or treated water environments when plant-specific operating experience has revealed selective leaching in these environments. For sample populations with greater than 35 susceptible components, two destructive examinations will be performed for that population. In addition, for sample populations with less than 35 susceptible components, one destructive examination will be performed for that population. For opportunistic and periodic inspections, 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 for each sample population. For one-time inspections, the number of visual and mechanical inspections may be reduced by two for each component that is destructively examined for each sample population.

Inspections will be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspection procedures will include requirements for items such as lighting, distance, offset, and surface conditions.

Inspection results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g.: selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

The acceptance criteria are indicated below.

- For copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide.
- For gray cast iron and ductile iron, the absence of a surface layer that can be easily removed by chipping or scraping or identified in the destructive examinations.
- The presence of no more than a superficial layer of dealloying, as determined by removal of the dealloyed material by mechanical removal.
- The components meet system design requirements such as minimum wall thickness, when extended to the end of the subsequent period of extended operation.

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 will be performed. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Extent of condition and extent of cause analysis will include evaluation of difficult-to-access surfaces if unacceptable inspection findings occur within the same material and environment population. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function.

NUREG-2191 Consistency

The *Selective Leaching* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.M33, "Selective Leaching."

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Selective Leaching* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2020, a risk assessment was performed for an industry fire main rupture event. In July 2019, the 12-inch fire water loop ruptured at Surry Power Station (SPS), while performing a monthly motor driven fire protection water pump periodic test. The cause of the pipe rupture was graphitic corrosion, found at the outside diameter in the cast iron pipe, which reduced the strength of the pipe. The pipe had ruptured as a result of the pressure surge caused by the

motor driven fire pump start. The graphitic corrosion was caused by wet soil which contributed to a higher corrosive soil environment. The thin asphalt coating could not protect the pipe in this higher corrosive index condition. The existing system design is similar to SPS in that an installed 12-inch buried fire main loop is supplied by electric and diesel driven fire pumps. However, significant selective leaching design differences, highlighted below, prevent pipe failure events.

Fire Main Specification Comparison:

SPS - cement lined, bell and spigot joints, cast-iron pipe, asphalt coated exterior, and cast-iron valve bodies

VCSNS - cement lined, bell and spigot joints, ductile iron pipe, asphalt coated exterior, cast-iron valve bodies, and utilizes a cathodic protection system to minimize corrosion

Conclusion:

Several key differences between the pipe and soil conditions are effective at reducing the graphitic corrosion causal factors including those listed below.

- The buried cementitious lined 12-inch fire main is ductile iron, not gray cast iron
- A cathodic protection system installed on the buried 12-inch fire main
- De-watering wells reduce the likelihood of fire service underground pipe/valves sitting in standing water for extended periods of time. Specifically, the wells maintain a low moisture content in the soil, reducing the likelihood of a higher corrosive index soil environment around the pipe.

Underground pipe/valves are inspected whenever exposed. Opportunistic inspections to date have not revealed any selective leaching of the buried fire service piping.

2. In January 2022, in support of initial license renewal, metallurgical analysis was performed on eight brass fire service system ball valves and seven buried gray cast iron fire service system components, consisting of post indicator valves and hydrants. The cross-sections performed on the brass valves found no evidence of any corrosion occurring along either the inner diameter or outer diameter. The gray cast iron valves and hydrants did show signs of minor corrosion typical of selective leaching or graphitic corrosion in gray cast iron components. The seven gray cast iron components displayed signs of corrosion/pitting occurring along the inner diameter of the valves. Only one of the gray cast iron components displayed any evidence of corrosion along the outside of the valve. The overall condition of the gray cast iron components was good, and the corrosion did not represent any long-term reliability concerns for the components.

3. In July 2022, a materials laboratory examination was conducted on five ring sections cut from three buried ductile iron fire service pipe segments. The internal cementitious lining was intact and tightly adhering. The examination focused on inspecting for evidence of selective leaching (graphitic corrosion) by grinding the cut faces of each sample flat to clean metal and examining for signs of pitting. The external surfaces of the ductile iron ring samples were free of any large deposits and rust blooms, showing only minor breaks in the form of rust spots in the asphaltic-based coating. The pitting noted on the outside diameter of the ring cross sections was mainly shallow and random. The components' intended function will be maintained based on the projected corrosion rate and measured extent of degradation.
4. In August 2022, a materials laboratory examination was conducted on four gray cast iron samples cut from fire service hydrants/post indicating valves. The examination focused on inspecting for evidence of selective leaching (graphitic corrosion) by grinding the cut faces of each sample flat to clean metal and examining for signs of pitting. Each of the valve samples showed some degree of minor pitting due to selective leaching. The majority of the pitting was observed on the internal surfaces. The degree of corrosion noted does not challenge the structural integrity of the valves. The overall condition of the valves was good.

The above examples of operating experience provide objective evidence that the *Selective Leaching* program will include activities to perform visual and mechanical inspections or destructive examinations to identify loss of material for piping, valve bodies and bonnets, pump casings, and heat exchanger components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Selective Leaching* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Selective Leaching* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Selective Leaching* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.22 ASME Code Class 1 Small-Bore Piping

Program Description

The *ASME Code Class 1 Small-Bore Piping* program is an existing condition monitoring program that manages cracking of ASME Code Class 1 small-bore piping that is defined as greater than or equal to one inch nominal pipe size (NPS) and less than four inches NPS. This program utilizes volumetric or destructive examinations to augment examinations performed by the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1).

The *ASME Code Class 1 Small-Bore Piping* program focuses on butt and socket welds for piping that is susceptible to stress corrosion cracking (SCC), and cracking due to thermal or vibratory fatigue loading. One-time and periodic inspections will be used to detect flaws and discontinuities that may indicate the presence of cracking for locations within the scope of the *ASME Code Class 1 Small-Bore Piping* program including full penetration (butt) and partial penetration (socket) welds.

Butt-Welded Piping

Age-related cracking has not been identified in Class 1 small-bore butt-welded piping. Therefore, consistent with NUREG-2191, Table XI.M35-1, Examinations, Category A criteria is required for examination of Class 1 small-bore butt welds. Accordingly, one-time inspection of butt welds will be performed with the examinations completed within the six-year period prior to the subsequent period of extended operation. The examination method will be volumetric or destructive with welds selected for examination from locations determined to be most risk significant and most susceptible to cracking. Should evidence of cracking be revealed by a one-time inspection, periodic inspections consistent with Category C criteria will be required for butt-welded piping.

Socket-Welded Piping

With exception of the reactor coolant pump (RCP) seal injection-thermal barrier (SI-TB) nozzle welds (discussed below), age-related cracking has not been identified in Class 1 small-bore socket-welded piping. Therefore, consistent with NUREG-2191, Table XI.M35-1, Examinations, Category A criteria is required for examination of Class 1 small-bore socket welds. Accordingly, one-time inspection of socket welds will be performed with the examinations completed within the six-year period prior to the subsequent period of extended operation. The examination method will be volumetric or destructive with welds selected for examination from locations determined to be most risk significant and most susceptible to cracking. Each socket weld subject to destructive examination may be credited twice toward the total number of examinations. Should evidence of cracking be revealed by a one-time inspection, periodic inspections consistent with Category C criteria will be required for socket-welded piping.

RCP Seal Injection-Thermal Barrier (SI-TB) Nozzle Socket Welds

For each RCP, the seal injection nozzle (pipe) is connected directly to the thermal barrier casing and is flanged at the other end to mate up with the seal injection line from the chemical and volume control system. The seal injection nozzle connects to the thermal barrier casing of each RCP with a partial penetration (socket) weld that was originally factory installed. There are three of these ASME Code Class 1 socket welds (i.e., one per RCP) that constitute a unique subset within the small-bore socket weld population.

The station has experienced cracking in the three factory-designed RCP SI-TB nozzle welds. Cracking in the 'C' RCP SI-TB partial penetration weld resulted in four separate reactor coolant pressure boundary leakage events in 1987, 1994, 2003, and 2004.

Following the 2004 leak, a root cause analysis was performed. The cause of the leak was attributed to low-amplitude high cycle fatigue. Factors which contributed to the fatigue process include the original weld geometry which created an inherent stress riser at the weld root, and installation with the end of the nozzle partially bottomed out in the socket causing residual tensile forces at the root notch. To mitigate the cause of cracking, the 'C' RCP seal injection line and associated nozzle weld were redesigned to reduce the vibration loads and to provide a more robust weld geometry. Specifically, the design included the following mitigating features:

- Nozzle nominal pipe size changed from SCH 80 to SCH 160
- SI-TB weld j-groove bevel increased from 30° to 45°
- Deeper partial penetration weld insertion
- Added rigid support anchored to the RCP main flange
- Spring can type support installed on upstream piping

As a result of the modifications to the 'C' RCP seal injection line, vibration was reduced substantially. With the more robust weld design and the reduced vibration levels, the cause of the cracking is considered to have been fully mitigated by design.

The vibration levels for the 'A' RCP and 'B' RCP SI-TB nozzles remained at acceptable levels and thus did not require re-design of the pipe supports. However, the 'A' RCP and 'B' RCP SI-TB nozzles and welds were replaced using the original factory weld detail. Therefore, the cause of cracking is not considered to be fully mitigated for this set of welds. Therefore, consistent with Table XI.M35-1, the three RCP SI-TB partial-penetration welds are treated as Category C. Should the 'A' RCP and 'B' RCP SI-TB nozzles and welds be replaced with the improved weld design, the set of welds will be inspected to Category B requirements consistent with NUREG-2191, Table XI.M35-1, Examinations.

The following table provides a summary of the number of one-time inspections and periodic inspections required for socket welds and butt welds:

Table B2.1.22-1 Summary of Inspections for Small-Bore Piping Welds

Weld Type	Table XI.M35-1 Category	Examination Schedule	Total Weld Population	Sample Size
Butt	A	One-time: completed within 6 years prior to the start of the subsequent period of extended operation	101	4 (3%, up to 10 max.)
Socket	A	One-time: completed within 6 years prior to the start of the subsequent period of extended operation	300+	10 (3%, up to 10 max.)
Socket (RCP SI-TB nozzles)	B (see Note 1)	One-time: completed within 6 years prior to the start of the subsequent period of extended operation	3	1 (10% up to 25 max)
Socket (RCP SI-TB nozzles)	C (see Note 2)	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	3	1 (10% up to 25 max)

Notes:

1. Category B will apply if the Class 1 RCP seal injection to thermal barrier nozzle welds have been replaced in their entirety, with the improved design. For this case, a one-time phased array UT inspection will be performed on the oldest redesigned SI-TB weld installed.
2. Category C will apply if the original RCP seal injection to thermal barrier nozzle weld design is still in use. For this case periodic phased array UT inspections will be performed on the original SI-TB nozzle welds.

NUREG-2191 Consistency

The *ASME Code Class 1 Small-Bore Piping* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M35, "ASME Code Class 1 Small-Bore Piping."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Parameters Monitored / Inspected (Element 3); Detection of Aging Effects (Element 4); Monitoring and Trending (Element 5); Acceptance Criteria (Element 6); and Corrective Actions (Element 7)

1. Procedure(s) will be revised to specify the following:
   - Perform one-time inspections of small-bore piping using the program methods and acceptance criteria.
   - Perform periodic inspections of reactor coolant pump seal injection to thermal barrier nozzle welds using the program methods, frequencies, and acceptance criteria.
   - Evaluate the results to determine if additional or periodic examinations are required.
   - Perform any required additional or periodic inspections.

Monitoring and Trending (Element 5)

2. Procedure(s) will be revised to require a subsequent re-examination after any component containing flaws or relevant conditions is accepted for continued service by analytical evaluation, in order to meet the intent of ASME Code, Section XI, Subarticle IWB-2420.

Acceptance Criteria (Element 6)

3. Procedure(s) will be revised to require examination results be evaluated in accordance with ASME Code, Section XI, Paragraph IWB-3132.

Corrective Actions (Element 7)

4. Procedure(s) will be revised to require corrective actions include examinations of additional ASME Code Class 1 small-bore piping welds, in order to meet the intent of ASME Code, Section XI, Subarticle IWB-2430.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Code Class 1 Small-Bore Piping* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. From 1987 to 2004, there has been a history of cracking in the three RCP SI-TB nozzle factory welds with reactor coolant pressure boundary leaks occurring in 1987, 1994, 2003, and 2004 in the 'C' RCP SI-TB nozzle weld. The three defective welds were replaced using the original Westinghouse weld joint design. However, after repair of the 2003 leak, vibration data was taken for the three RCP seal injection lines during startup. The 'C' RCP seal injection line

exhibited a natural frequency similar to the pump vibration frequency and resulted in cyclic displacement amplitudes about six times those seen in the similar 'A' RCP and 'B' RCP seal injection lines. The vibration data was evaluated by Engineering and determined to be acceptable for the near term (the following few cycles). However, it was recommended to reduce the vibration in the 'C' RCP seal injection line. Subsequently, following the 2004 leak, detailed inspections and metallurgical testing were performed and additional vibration data obtained.

The test results indicated that the failure of the 'C' RCP SI-TB nozzle weld was entirely due to low-amplitude high cycle fatigue. The weldment was found to be sound. Three factors appeared to dominate the fatigue process as follows:

a. The geometry at the weld root created an inherent stress riser that intensified the cyclic vibrational loads at the weld root.

b. The end of the nozzle impacted the bottom of the socket over a portion of the circumference and the inner surface of the pipe was displaced inward towards the pipe axis. This produced residual tensile forces at the root notch that opened the root notch and produced a crack starter (hot tear).

c. The crack starter effectively eliminated the crack initiation portion of fatigue life (crack initiation consumes about 80% of fatigue life as a rule of thumb).

These three factors concurrent with pump vibration produced sufficient stress to drive the crack completely through wall in less than six months. Fatigue propagation was entirely transgranular and there was no evidence of corrosion processes having influenced the fatigue propagation.

Modifications were performed on the 'C' RCP seal injection line to address the failure mechanisms identified. These modifications included:

- Installation of a new nozzle design using heavier pipe and a more robust weld.
- Use of 1/8-inch pullback on new nozzle fit-up.
- Liquid penetrant (PT) examination of each weld pass (which exceeded the ASME code requirements) and an informational post-weld ultrasonic ID examination of the weld.
- Installation of a new rigid pipe support to increase the resonant frequency and reduce vibration loading on the nozzle.
- Installation of a new spring can pipe support on the seal injection line.

Post-modification measurement of the 'C' RCP seal injection line natural frequency and vibration performed at Mode 3 during startup verified that displacements had been significantly reduced and natural frequency shifted away from pump driving frequency.

2. During the period from Fall 2012 through Fall 2021, ultrasonic (UT) examinations were performed on welds and adjacent piping identified as potentially susceptible to thermal fatigue using the guidance of MRP-146, “Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines.” The inspections were performed on 3 inch NPS butt welds and 2 inch NPS socket welds located in normally stagnant Class 1 branch lines. In addition, in support of the “Small Bore Class 1 Piping Inspection” one-time inspection activity for initial license renewal, during the period from Spring 2017 through Fall 2021, volumetric examinations were performed on Class 1 small-bore full penetration (butt) welds and partial penetration (socket) welds. These additional inspections were performed consistent with NUREG-1801, Revision 2, XI.M35 at locations determined to be most susceptible to cracking based on engineering evaluation, operating experience, code requirements, industry initiatives, and accessibility. For these inspections, ultrasonic (UT) examinations were performed on full-penetration welds and phased array ultrasonic (PAUT) examinations were performed on partial-penetration welds.

   No recordable indications were identified by these inspections.

The above examples of operating experience provide objective evidence that the *ASME Code Class 1 Small-Bore Piping* program includes activities to perform volumetric inspections to identify cracking and SCC for Class 1 small-bore piping within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *ASME Code Class 1 Small-Bore Piping* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME Code Class 1 Small-Bore Piping* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Code Class 1 Small-Bore Piping* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.23 External Surfaces Monitoring of Mechanical Components

Program Description

The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that manages the following aging effects:

- Cracking and Loss of material of metallic components.
- Hardening or loss of strength, loss of material, and cracking or blistering of polymeric components.
- Hardening or loss of strength and loss of material of elastomeric components.
- Loss of material, cracking, and loss of preload of HVAC closure bolting.
- Reduced thermal insulation resistance.

Visual inspections are performed during system inspections and walkdowns. The inspection parameters for metallic components include material condition, which consists of evidence of rust, pitting, crevice, and general corrosion; surface imperfections such as cracking and wastage; coating degradation such as cracking, flaking, or blistering; evidence of insulation damage or wetting; leakage from piping, ducting, or component bolted joints; and accumulation of debris on heat exchanger surfaces. Coating degradation is used as an indicator of possible degradation on underlying surfaces of the component. Inspection parameters for elastomeric and polymeric components include blistering, hardening, discoloration, surface cracking, crazing, scuffing, loss of thickness, exposure of internal reinforcement, and dimensional changes. For certain materials, such as flexible polymers, physical manipulation to detect hardening or loss of strength is used to augment the visual inspections conducted under this program.

Periodic visual inspections, not to exceed a refueling outage interval, of metallic and polymeric components and insulation jacketing (insulation when not jacketed) will be conducted. This frequency accommodates inspections of components that may be in locations that are normally only accessible during refueling outages. Surfaces that are not readily visible during plant operations and refueling outages will be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained. There are no cementitious components within the scope of this program.

ASME Code, Section XI visual examinations (VT-1) or surface examinations will be conducted to detect cracking of copper alloy (>15% Zn) components exposed to aqueous solutions or aggressive air environments. A representative sample will be performed from the copper alloy (>15% Zn) component population every 10 years. Examinations will be conducted on 20% of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components will be inspected.

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), will be periodically inspected every 10 years during the subsequent period of extended operation. Following insulation removal, ASME Code, Section XI visual examinations (VT-1) or surface examinations will be conducted to detect loss of material and cracking of the component surfaces. A minimum of 20% of the in-scope piping length, or 20% of the surface area for components whose configuration does not conform to a one-foot axial length determination will be inspected. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components for each material type will be inspected.

If any sampling-based inspections to detect cracking in copper alloy (>15% Zn) components do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. The additional inspections will be completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.

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 site procedures consistent with the ASME Code. Non-ASME Code inspection procedures include requirements for items such as lighting, distance, offset, surface coverage, and presence of protective coatings.

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. For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

The external surfaces of components that are buried or in underground environments are inspected by the *Buried and Underground Piping and Tanks* program (B2.1.28). The external surfaces of outdoor tanks and indoor large volume metallic storage tanks (capacity >100,000 gallons) are inspected by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (B2.1.17). Loss of material due to boric acid corrosion is managed by the *Boric Acid Corrosion* program (B2.1.4).

The *External Surfaces Monitoring of Mechanical Components* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *External Surfaces Monitoring of Mechanical Components* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M36, “External Surfaces Monitoring of Mechanical Components.”

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Detection of Aging Effects (Element 4)

1. Procedure(s) will be revised to specify that walkdowns will be performed at a frequency not to exceed one refueling cycle. Since some surfaces are not readily visible during both plant operations and refueling outages, surfaces will be inspected when they are made accessible and at intervals that would ensure the components' intended functions are maintained.
2. Procedure(s) will be revised to specify that visual inspections of elastomers and flexible polymers will cover 100% of accessible component surfaces. The minimum surface area for tactile inspections of elastomers and flexible polymers will be at least 10% of the accessible surface area.

Detection of Aging Effects (Element 4) and Corrective Actions (Element 7)

3. Procedure(s) will be revised to specify the following to manage cracking of copper alloy (>15% Zn) components and cracking and loss of material of insulated outdoor/indoor components exposed to condensation populations:
    a. In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed. Examinations for cracking will be performed from the copper alloy (>15% Zn) component population every 10 years. Examinations are conducted on 20% of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of a minimum of 25 one-foot axial length

sections and components is inspected. For insulated outdoor components and indoor components exposed to condensation, following insulation removal, a minimum of 20% of the in-scope piping length, or 20% of the surface area for components whose configuration does not conform to a one-foot axial length determination is inspected for loss of material and cracking. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components for each material type is inspected. The new procedure will specify that the inspections focus on the components most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin.

b. Additional inspections will be performed if any sampling-based inspections to detect cracking in copper alloy (>15% Zn) components do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.

Monitoring and Trending (Element 5) and Corrective Action (Element 7)

4. Procedure(s) will be revised to evaluate and project the rate of degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.

Acceptance Criteria (Element 6)

5. Procedure(s) will be revised to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *External Surfaces Monitoring of Mechanical Components* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In November 2013, during walkdown of the chilled water system, rust and pitting were identified on a ½-inch capped carbon steel piping test connection downstream of the 'C' chilled water pump. The condition was evaluated and the structural integrity of the piping was determined to be acceptable. To prevent further degradation, the pipe was cleaned, painted and new insulation installed.
2. In March 2017, during maintenance on 'A' emergency diesel generator (EDG), while removing a 4-inch lube oil flexible coupling, a crack was found on the cast-iron flexible coupling follower. The coupling did not have any signs of previous oil leakage and the crack appeared to exist prior to the maintenance activity. A replacement coupling with carbon steel followers was installed. Subsequent inspection and performance of the Technical Specification monthly surveillance test of the 'B' EDG did not identify any cracks, leaks or abnormal conditions.
3. In February 2017, during cleaning and inspection of 'A' EDG heat exchangers, surface rust, flaking paint, discoloration, and rough areas on the surface of the service water pipe located between the intercooler heat exchanger and the jacket cooling water heat exchanger were identified. The surface rust and flaking paint were removed and the pipe was prepped and painted.
4. In June 2017, Engineering identified that the rubber discharge expansion joints serving the emergency feedwater pump area cooling units were leaking slightly around the entire perimeter. Further inspection of the expansion joints reveals they were hardened due to age and required replacement. Although the cooling units were determined to be operable, the rubber expansion joints were replaced for both 'A' and 'B' cooling units.
5. In Fall 2019, a sample of chilled water system piping and components were inspected for corrosion under insulation. These inspections were completed in support of an initial license renewal commitment to perform inspections of mechanical components every five years. Piping and components were selected for inspection in 11 areas of the chilled water system based on water staining observed on insulation, damaged insulation, previous inspection history, and opportunistic maintenance. During these inspections, general corrosion, flaking of coatings, and pitting was identified. Pitted piping was either evaluated as acceptable or replaced with new piping. Piping and components were cleaned, painted and new insulation installed. Based on the as-left conditions, the components were expected to perform their intended functions past the next inspection opportunity.

6. In November 2019, while performing a walkdown of service water piping to the 'A' component cooling water heat exchanger, portions of the 'A' component cooling water heat exchanger shell were identified with peeling paint and minor surface corrosion. The heat exchanger shell was cleaned, prepped, and painted.

The above examples of operating experience provide objective evidence that the *External Surfaces Monitoring of Mechanical Components* program includes activities to perform visual inspections to manage aging effects of components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *External Surfaces Monitoring of Mechanical Components* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *External Surfaces Monitoring of Mechanical Components* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *External Surfaces Monitoring of Mechanical Components* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.24 Flux Thimble Tube Inspection

Program Description

The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that manages loss of material due to wear by inspecting for thinning of the flux thimble tube walls. Flux thimble tubes provide a path for the incore neutron flux monitoring system detectors and form part of the reactor coolant system pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor pressure vessel (RPV) where flow-induced fretting causes wear at discontinuities in the path from the RPV instrument nozzle to the fuel assembly instrument guide tube. Such discontinuities could be present in the areas of the lower core plate, the lower internals support column, and the RPV penetration nozzle. The flux thimble tubes are a single tube design. Degradation of the flux thimble tubes creates the potential for damage to the detectors if exposed to the RPV environment conditions.

Periodic eddy current testing (ECT) is performed to confirm the integrity of the flux thimble tubes consistent with the recommendations of NRC Inspection and Enforcement Bulletin (IEB) 88-09, “Thimble Tube Thinning in Westinghouse Reactors,” and WCAP-12866, “Bottom Mounted Instrumentation Flux Thimble Wear.”

In response to IEB 88-09, flux thimble tubes were initially required to be replaced or repositioned if 60% through-wall thinning was experienced and ECT was performed every refueling. With the January 1991 issuance of WCAP-12866, criterion was adopted that a wall loss of 80% would be used to determine when flux thimble tube action (e.g., repositioning, replacement, etc.) was required. The incore flux thimble tubes wear assessment procedure, an acceptance criterion of 75% was used for conservatism to determine when flux thimble tube action was required. Trending of previous wear results and wear projections for future cycles are shown in attachments to the incore flux thimble tube wear assessment procedure.

Following flux thimble tube failures in 2015 and 2018, the ECT acceptance criteria were made more conservative to require ECT during the next refueling outage in which any flux thimble tubes will have >50% projected wear. Repositioning is required if >60% wear is measured or if >70% wear is projected. If >75% wear is measured, the flux thimble tube is replaced or capped as determined by Engineering.

Results of previous examinations are utilized to determine any trend for the extent of flux thimble tube wall thinning. Compensatory action is taken for any flux thimble tube that has a remaining wall thickness that is less than the minimum allowable, or is projected to reach minimum allowable wall thickness prior to the next inspection.

The *Flux Thimble Tube Inspection* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Flux Thimble Tube Inspection* program is an existing program that is consistent with NUREG-2191, Section XI.M37, “Flux Thimble Tube Inspection.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Flux Thimble Tube Inspection* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2015, a flux thimble tube (B-10) failed during cycle 22. The isolation valve for location B-10 was closed to terminate the leakage. During the Fall 2015 refueling outage, a camera inspection of the portion of the B-10 flux thimble tube that is inserted into the RPV verified that through wall leak occurred around the area of the lower internals as industry operating experience suggested. As an extent of condition, the 50 flux thimble tubes were replaced with equivalent spares during the Fall 2015 refueling outage. A preventive maintenance item was also generated to eddy current test the flux thimble tubes on an every third refueling outage frequency regardless of the wear projections determined by the incore flux thimble tube wear assessment procedure.
2. In 2018, a flux thimble tube (B-7) failed during cycle 24. Following evaluation of eddy current testing results during the Fall 2018 refueling outage, 13 flux thimble tubes were determined to need replacement because they either had greater than or equal to 50% wall loss, had been repositioned, the detector would not pass through, or had been isolated for other reasons. The 13 flux thimble tubes were replaced during the Fall 2018 refueling outage with an enhanced wear-resistant chrome-plated design. Eddy current testing was scheduled for the Spring 2020 refueling outage to baseline wear rates with the new flux thimble tube material.

3. In April 2020 during the Spring 2020 refueling outage flux thimble tube inspection, ECT identified no detectable wear damage in any of the 13 chrome-plated design replacement flux thimble tubes. Of the remaining flux thimble tubes, the highest recorded wear measurement was 52%. No flux thimble tubes required repositioning, capping, or replacement. Due to actual wear exceeding 50%, the next flux thimble tube inspection was procedurally required during the Fall 2021 refueling outage.
4. In January 2021, based on the flux thimble tube failures in 2015 and 2018, a revision to the incore flux thimble tube wear assessment procedure was implemented with more conservative ECT acceptance criteria. Eddy current testing is now required in a future outage if any flux thimble tubes have >50% projected wear. Repositioning or isolation is required if >60% wear is measured or if >70% wear is projected. If >75% wear is measured, the flux thimble tubes must be replaced or capped. This revised procedure would be used to evaluate the Fall 2021 refueling outage flux thimble tube inspection results.
5. In October 2021, during the Fall 2021 refueling outage flux thimble tube inspection ECT identified no detectable wear damage in any of the 13 chrome-plated design replacement flux thimble tubes. Of the remaining flux thimble tubes, the highest recorded wear measurement was 63%. Thimble tube N-12 was isolated due to exceeding 60% wear. Due to projected wear exceeding 50%, the next flux thimble tube inspection is procedurally required during the Spring 2023 refueling outage.

The above examples of operating experience provide objective evidence that the *Flux Thimble Tube Inspection* program includes activities to perform eddy current testing to identify loss of material for the pressure boundary provided by the flux thimble tubes, and to initiate corrective actions. Occurrences identified under the *Flux Thimble Tube Inspection* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Flux Thimble Tube Inspection* program will effectively manage aging prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The continued implementation of the *Flux Thimble Tube Inspection* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that manages the following aging effects:

- Cracking or blistering, hardening or loss of strength, and loss of material of polymeric components
- Flow blockage, hardening or loss of strength, and loss of material of elastomeric components
- Cracking, flow blockage, loss of material, and reduction of heat transfer of metallic components

This program consists of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, tanks, and other components exposed to closed-cycle cooling water, raw water, treated water, diesel exhaust, air, condensation, lubricating oil, and waste water. Aging effects associated with items within the scope of the *Open-Cycle Cooling Water System* program (B2.1.11), *Closed Treated Water Systems* program (B2.1.12), and *Fire Water System* program (B2.1.16) are not managed by this program.

Inspections of metallic components monitor for visible evidence of loss of material. Indicators of aging effects for metallic components include corrosion and surface imperfections; loss of wall thickness; flaking or oxide-coated surfaces; debris accumulation on heat exchanger tube surfaces; and accumulation of particulate fouling, biofouling, or macro fouling.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of aluminum, copper alloy (>15% Zn), and stainless steel components.

Inspections of polymeric and elastomeric components monitor for changes in material properties or loss of material. Indicators of loss of material and changes in material properties include surface cracking, crazing, scuffing, loss of sealing, dimensional change, loss of wall thickness, discoloration, exposure of internal reinforcement, hardening, and blistering. 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.

The internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population will be inspected.

If any inspections do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination. The additional inspections will be completed within the interval (i.e., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval.

Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections will continue in each period, even if the minimum number of inspections has been conducted.

Inspections will be 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 inspection procedures include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

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. For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.”

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Detection of Aging Effects (Element 4)

1. Procedure(s) will be revised to specify inspections and tests be performed by personnel qualified in accordance with site procedures and programs to perform the specified task.
2. Procedure(s) will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. Adequate lighting will be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. For internal inspections, accessible surfaces will be inspected. If inspecting piping internal surfaces, a minimum of one linear foot will be inspected, if accessible. Cleaning will be performed as necessary to allow for a meaningful examination. If protective coatings are present, the condition of the coating will be documented.

Detection of Aging Effects (Element 4); Monitoring and Trending (Element 5); Acceptance Criteria (Element 6); and Corrective Actions (Element 7)

3. Procedure(s) will be revised to specify the following:
    a. In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 25 components per population will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions.

b. The rate of degradation will be evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g.: selection, size, frequency) will be adjusted as necessary based on the projection.

c. Additional inspections will be performed if any sampling-based inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination. The additional inspections will be completed within the interval (e.g.: refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval.

Acceptance Criteria (Element 6)

4. Procedure(s) will be revised to specify that, where practical, acceptance criteria are quantitative (e.g.: minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In July 2014, leakage was discovered in nonsafety-related piping downstream of the 'A' train service water jet air exhauster. The 2-inch diameter carbon steel piping downstream of the jet air exhauster was corroded and leaking, allowing water to flow through the penetration to the 'A' train service water pump pit room. After removing the damaged piping, an internal

inspection found extensive biological fouling with pitting and general wall thinning. Corrective actions included replacement of the damaged 2-inch piping and approximately 14 feet of 3-inch piping upstream of the leak location. The cause of the leak was attributed to microbiologically influenced corrosion (MIC). Following replacement of the 'A' train service water piping, a system pressure test was performed on the new piping with no leakage identified. Subsequently, in October 2018, a leak was discovered at the penetration for the 'B' service water pump pit room in the 2-inch diameter piping downstream of the 'B' train service water jet air exhauster. For this operating experience example, the cause was assumed to be attributed to MIC, similar to the leak identified in July 2014 for the 'A' train service water piping. Corrective actions included replacement of the damaged 2-inch piping and approximately 14 feet of 3-inch piping upstream of the leak location. Following replacement of the 'B' train service water piping, a system pressure test was performed on the new piping with no leakage identified.

2. In November 2019 (RF25), periodic internal inspections were performed on the four reactor building cooling units (RBCU). This included inspections of the flex joints, plenum walls and floor, cooling coils, and fins. The elastomeric flex joints were inspected for holes, tears and flexibility. The plenum housing, cooling coils, and fins were inspected for corrosion. During the inspection, dry boric acid accumulation was observed on the floors, walls, fan housings, coils, and fins of each unit. The inspection also identified minor corrosion on the walls and coils. The leak was inspected and evaluated as required by the Boric Acid Corrosion program. Engineering performed an inspection following cleaning and determined that the RBCUs were acceptable for continued service. Subsequent periodic inspections of the RBCUs performed during RF26 (Fall 2021) and RF27 (Spring 2023) did not identify appreciable degradation.

Recurring Internal Corrosion (RIC)

A review of operating experience since 2011 indicates that recurring internal corrosion (RIC) has occurred in the service water system piping and piping components within the scope of this program due to microbiologically influenced corrosion (MIC). Loss of material due to MIC has resulted in through-wall leakage in two non-sequential cycles during the five-year period from 2014 to 2018. In July 2014, loss of material due to MIC resulted in through-wall leakage in piping downstream of the 'A' train service water air jet exhauster. Subsequently, in October 2018, a similar leakage event occurred in the piping downstream of the 'B' train service water air jet exhauster.

Corrective action for the overall concern of corrosion in service water piping has included adjustments of the chemical treatment for the service water system to inhibit biological growth and fouling, and reduce loss of material.

Based on operating experience, additional adjustments of the chemical treatment have occurred as needed. The current chemical treatment has been in use since 2015 and includes a macro-biocide, a micro-biocide, bio-dispersant, corrosion inhibitor, dispersant, and azole.

Operating experience since 2015 indicates that the chemical treatments have been effective in addressing MIC. The ongoing chemical treatment and planned periodic inspections provide reasonable assurance that MIC will be managed before a loss of component function.

The above examples of operating experience provide objective evidence that the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program includes activities to perform opportunistic inspections to identify cracking, flow blockage, loss of material, and reduction of heat transfer of metallic components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program, following enhancement, will effectively identify aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.26 Lubricating Oil Analysis

Program Description

The *Lubricating Oil Analysis* program is an existing preventive program that ensures loss of material and reduction of heat transfer is not occurring by maintaining the quality of the lubricating oil or hydraulic oil. The program will ensure that contaminants (primarily water and particulates) are within acceptable limits and are consistent with vendor and industry guidelines.

The program directs condition monitoring activities (sampling, analyses, and trending), thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. The lubricating oil testing (sampling and analysis) and condition monitoring activities identify detrimental contaminants such as water, sediments, specific wear elements, and elements from an outside source. The contaminant levels (e.g., water and particulates) will be monitored and trended, and corrective actions will be initiated when the presence of water or particulate is identified that either indicates an adverse trend or established acceptance criteria is not met.

The *Lubricating Oil Analysis* program applies monitoring methods that are effective in detecting contaminants and the frequency of monitoring is adequate to prevent significant degradation based on operating experience.

To verify the effectiveness of the *Lubricating Oil Analysis* program, selected components will be inspected as described in the *One-Time Inspection* program (B2.1.20) to confirm degradation is not occurring and the component's intended functions will be maintained during the subsequent period of extended operation.

NUREG-2191 Consistency

The *Lubricating Oil Analysis* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M39, “Lubricating Oil Analysis.”

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Scope of Program (Element 1); Preventive Actions (Element 2; Detection of Aging Effects (Element 4); and Acceptance Criteria (Element 6)

1. Procedure(s) will be revised to require periodic sampling and testing of the reactor building chiller oil for water and particulates. Procedure(s) will include water and particulate limits.

Preventive Actions (Element 2); Detection of Aging Effects (Element 4); and Acceptance Criteria (Element 6)

2. Procedure(s) will be revised to include:

   Water Testing:

   Water in oil will be monitored with the Visual Crackle Test or other first level water content test. The target value for water concentration will be less than or equal to 500 ppm (0.05%). If water content is nominally greater than 500 ppm (i.e., it fails the crackle test or other first level water content test), a confirmatory water analysis consistent with ASTM D6304 (Karl-Fischer titration test) or equivalent method will be performed to determine if the water content is within the limits specified in plant procedures.

   Phase-separated water in any amount is not acceptable.

   Particulate limits:

   Procedure(s) will be revised to specify established particulate limits that are based on equipment manufacturer's recommendations or industry standards.

Parameters Monitored / Inspected (Element 3)

3. Procedure(s) will be revised to require sampling lubricating oil for particulate and performance of a particle count analysis.

Detection of Aging Effects (Element 4)

4. Procedure(s) will be revised to require sampling and testing following periodic oil changes or on a schedule consistent with equipment manufacturer's recommendations or industry standards.

Monitoring and Trending (Element 5)

5. Procedure(s) will be revised to require that water and particulate test results are monitored to identify adverse trends that require corrective action(s).

Corrective Actions (Element 7)

6. Procedure(s) will be revised to require initiating a condition report if the data collected exceed an alert limit or indicate an unexpected negative trend. Corrective actions will be determined by the Corrective Action Program, and may include increased monitoring, corrective maintenance, further laboratory analysis, and engineering evaluation of the system.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Lubricating Oil Analysis* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In February 2012, a routine heating, ventilation and air conditioning 'A' mechanical chiller refrigerant compressor oil sample was brought to the oil lab for analysis. The oil was grey in appearance. Analysis of the sample indicated a high whole particle count due to normal break-in wear of the new chiller, with a few wear particles exceeding 15 microns in size. The viscosity of the sample was low out of specification. The oil was drained from the chiller's compressor sump, new oil was added, and the chiller was then run for a short period to allow any remaining oil in the system to return to the sump. Subsequently, an additional oil sample was taken and analyzed with normal results and appearance. Following replacement of the oil, the chiller operated normally, with no evidence of damage to the compressor. At the next scheduled oil sample in February 2014, the results were satisfactory.
2. In June 2013, a routine annual oil sample was taken from the outboard bearing of the 'B' emergency feedwater pump. Multiple debris types were observed and analyzed in the sample. The ferrography results failed due to particle size exceeding 15 microns. The metal particles in the sample were 20-40 microns in size while normal sample background size is <15 microns. Engineering assessed that the bearing was in the first of four stages of failure. The first stage typically yields 10-20% remaining life or ~100,000 hours, which for a standby pump, results in a bearing life that easily exceeds the time until the next pump refurbishment. Since the expected bearing life (~100,000 hours) far exceeded the expected pump runtime before the next maintenance evolution (1000 hours), it was concluded that an increase in the oil sampling frequency was not justified. The outboard bearing oil was changed out during performance of the work order task. An oil sample collected after oil replacement and a 45-minute run was satisfactory with no signs of wear. This trend continued with subsequent samples.
3. In November 2015, Engineering recommended that the 'C' reactor coolant pump (RCP) motor oil in the upper and lower oil reservoirs be changed out due to depleting anti-oxidation additive in the oil. Depletion of anti-oxidant additive occurs during the normal use of oil. A complete depletion of anti-oxidant additive in combination with high oil temperatures (>185 deg F) can cause the oil to create carboxylic acids, which could cause corrosion of the RCP lubricating oil system. Since the oil had been in service since 2008, a conservative decision was made to replace the oil rather than running another 18-month cycle and the oil potentially breaking down mid-cycle. Following replacement, analysis results showed no indication of chemical breakdown in the oil.

4. In November 2018, oil samples from 'A' RCP and 'B' RCP upper lube oil reservoirs yielded unsatisfactory results on appearance. The oil was visually milky with solids suspended within the samples. Backup samples confirmed the unsatisfactory results. Chemistry personnel, in consultation with station management recommended that the oil in both affected reservoirs be changed out. Following a 5-gallon flush, additional backup samples were drawn from both 'A' and 'B' RCP upper lube oil reservoirs. These samples still exhibited a milky appearance that indicated oil was questionable for use. The oil in both reservoirs was fully drained and replaced. Follow-up samples were collected and the results were satisfactory. At the next scheduled oil sample (April 16 and 18, 2020), the results were again satisfactory.

The above examples of operating experience provide objective evidence that the *Lubricating Oil Analysis* program includes activities to perform lubricating oil analysis to identify any degradation in the quality of the lubricating oil or hydraulic oil that could cause loss of material or reduction of heat transfer for components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Lubricating Oil Analysis* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Lubricating Oil Analysis* program, following enhancement, will effectively identify aging, prior to a loss of intended function.

Conclusion

The continued implementation of the *Lubricating Oil Analysis* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.27 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

Program Description

The *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program is an existing condition monitoring program that manages loss of material and degradation of the Boral® neutron-absorbing panels used in the spent fuel pool racks. The monitoring program assures that degradation of the neutron-absorbing material used in spent fuel pools that could compromise the spent fuel pool criticality analysis will be detected. The program relies on periodic inspection, testing, monitoring, and potential re-analysis of the spent fuel pool criticality design to assure that the required 5% sub-criticality margin will be maintained during the period of subsequent license renewal.

Sixteen Boral® coupons were provided when the higher density spent fuel racks were manufactured and installed in the spent fuel pool in 2003. The coupons are representative 4x8 inch samples from the same manufacturing lots which produced the Boral® neutron absorbing panels attached to the new fuel racks.

The Boral® coupons are bolted to a specimen tree structure in order to maintain their axial spacing. The Boral® coupon specimen tree is placed on the spent fuel racks in a high dose area within the Region 2 spent fuel. The specimen support structure contacts the fuel rack baseplate, so the Boral® coupons experience the same galvanic environment as the full-size Boral® panels attached to the racks.

During each reload cycle, the specimen tree is surrounded by four freshly-discharged fuel assemblies to ensure that the coupons experience a bounding radiation field and thermal load.

The *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program withdraws, inspects, and tests one of the remaining Boral® coupons at a 10-year minimum frequency consistent with NEI 16-03, “Guidance for Monitoring of Fixed Neutron Absorbers in Spent Fuel Pools.” The program measures the withdrawn Boral® coupon for swelling. If the Boral® coupon dimensional measurements indicate excessive swelling, an engineering evaluation will be performed for the spent fuel racks to ensure the any swelling has not induced rack dimensional changes which could cause excessive drag forces on spent fuel assemblies.

Neutron attenuation testing is performed on the withdrawn Boral® coupon to determine Boron-10 areal density. A 5% decrease below initial Boron-10 areal density indicates measurable degradation and would result in an increased Boral® coupon inspection frequency. A measured Boron-10 areal density below that the value assumed in the spent fuel pool criticality analysis would require re-evaluation of the spent fuel pool criticality analysis and a potential Technical Specification change.

NUREG-2191 Consistency

The *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program is an existing program that is consistent with NUREG-2191, Section XI.M40, “Monitoring of Neutron-Absorbing Materials Other Than Boraflex.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2003, the original Boraflex® panels attached to racks in the spent fuel pool were replaced with Boral® neutron-absorbing panels attached to new spent fuel racks. Sixteen Boral® coupons were provided which were representative 4x8 inch samples from the same manufacturing lots which produced the full-sized Boral® neutron absorbing panels. The representative set of Boral® coupons was installed and is maintained in a high flux/high thermal load region of the spent fuel pool to ensure that subsequent Boral® coupon testing would provide evidence of the aging effects representative of those experienced by the full-sized Boral® panels attached to the new spent fuel pool racks. The as-built Boral® coupon dimensions and Boron-10 areal density serve as baselines for future measurements and Boron-10 areal density testing.
2. In May 2011, the first of 16 installed Boral® coupons was removed, examined, and tested. No blistering, bulging, pitting, or warping of the coupon was observed. The measured dimensions and parameters were within expected ranges. Neutron attenuation testing of the Boral® coupon provided no indication of loss of neutron absorbing material. Therefore, the estimated minimum Boron-10 areal density of the withdrawn Boral® coupon as measured in 2011 was the same as when the material was installed in the spent fuel pool in 2003.
3. In November 2016, information requested in NRC Generic Letter 16-01 (GL 16-01), “Monitoring of Neutron-Absorbing Materials in Spent Fuel Pools” (ADAMS Accession No. ML16097A169) was submitted to the NRC (ADAMS Accession No. ML16312A177). The submittal documented VCSNS Unit 1 was a Category 4 licensee and specified Boral® as the neutron absorber credited in the spent fuel pool criticality analysis. Based on the Boral® neutron absorbing panels, information for a Category 4 licensee crediting Boral® was provided

regarding the credited neutron absorber material, spent fuel pool criticality analysis of record, and neutron absorber monitoring program was provided, as requested in Attachment A to GL 16-01. As stated in the response, the neutron absorber coupon monitoring program follows guidance provided in NEI 16-03, "(DRAFT) Guidance for Monitoring of Fixed Neutron Absorbers in Spent Fuel Pools," May 2016, for Boral® coupons constructed from the same manufacturing lots as the full-sized Boral® panels. Results from the Coupon 1 2011 withdrawal inspection, dimensional measurement, and Boron-10 area density testing, were utilized to demonstrate there was no measured degradation of the analyzed coupon since installation in 2003. The response to GL 2016-01 confirms the Boral® coupon surveillance program and the first coupon withdrawal and associated testing for the Boral® neutron absorbing panels followed industry guidance and met the requirements of Generic Letter 2016-01, which was later incorporated by the NRC as the basis for the *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program (B2.1.27).

4. In August 2021, the second of 16 installed Boral® coupons was removed, examined, and tested. No blistering, bulging, pitting, or warping of the coupon was observed. The measured dimensions and parameters were within expected ranges. Neutron attenuation test results of the Boral® coupon indicated a 1.8% average decrease in Boron-10 areal density over the five measured locations. The surveillance results were satisfactory.

The above examples of operating experience provide objective evidence that the *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program includes activities to perform dimensional and Boron-10 areal density measurements to identify loss of material and degradation of the Boral® neutron-absorbing components/materials used in the spent fuel racks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The implementation of the *Monitoring of Neutron-Absorbing Materials Other Than Boraflex* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.28 Buried and Underground Piping and Tanks

Program Description

The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that manages loss of material on external surfaces of piping, piping components and tanks in soil, concrete, or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses buried and underground piping and tanks in the following systems.

Buried carbon steel piping and components, gray cast iron components (fittings), and ductile iron piping and components in:

- Emergency Feedwater
- Diesel Generator Services
- Fire Service
- Service Water

Buried carbon steel tanks in:

- Diesel Generator Services

Underground stainless steel and carbon steel bolting in:

- Safety Injection
- Reactor Building Spray

Depending on the material, preventive and mitigative techniques include external coatings, cathodic protection, and the quality of backfill. Direct visual inspection quantities for buried components are planned using procedural categorization criteria. Transitioning to a higher number of inspections than originally planned is based on the effectiveness of the preventive and mitigative actions. Also, depending on the material, inspection activities include annual surveys of cathodic protection, non-destructive evaluation of pipe or tank wall thicknesses, and visual inspections of the pipe from the exterior. Opportunistic external inspections of buried components within the scope of subsequent license renewal occur when they become accessible.

An active cathodic protection system is used to protect the buried carbon steel piping of the emergency feedwater, diesel generator services, and service water systems and the ductile iron piping of the fire service system. Additionally, the two carbon steel fuel oil storage tanks of the diesel generator services system are cathodically protected. Periodic inspections confirm cathodic protection system availability and reliability. Annual cathodic protection surveys are conducted to assess the effectiveness of the cathodic protection system. The program uses the -850 mV relative to copper/copper sulfate reference electrode (CSE), instant off criterion specified in NACE SP0169-2007 for acceptance criteria for steel piping and tanks and determination of cathodic protection system effectiveness in performing cathodic protection surveys. The program will specify that the limiting critical potential for the cathodic protection system should not be more negative than -1,200 mV to prevent damage to the coating. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured. The cathodic protection system will be refurbished, upgraded, and augmented by replacing depleted anodes, installing additional anodes, and upgrading and replacing rectifiers.

Soil sampling and testing is performed during each excavation and a station-wide soil survey based on initial baseline data is also performed once in each 10-year period to confirm the soil corrosivity level near components within the scope of subsequent license renewal for the installed material types. Soil sampling and testing is consistent with EPRI Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants." Soil corrosivity analysis was most recently performed in 2020.

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the subsequent period of extended operation, an increase in the sample size is conducted.

The *Buried and Underground Piping and Tanks* program conducts periodic and opportunistic visual inspections of the buried fire service system piping and components that facilitates examinations performed by the *Selective Leaching* program (B2.1.21) to manage loss of material due to selective leaching for applicable materials in soil environments.

The *Buried and Underground Piping and Tanks* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Buried and Underground Piping and Tanks* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M41, "Buried and Underground Piping and Tanks."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Preventive Actions (Element 2) and Parameters Monitored / Inspected (Element 3)

1. Procedure(s) will be revised to specify that the limiting critical potential for the cathodic protection system should not be more negative than -1,200 mV to prevent damage to the coating.

Preventive Actions (Element 2); Detection of Aging Effects (Element 4); and Corrective Actions (Element 7)

2. The nine cathodic protection systems will be refurbished and upgraded to improve reliability. The refurbishment and upgrades will be implemented five years prior to entering the subsequent period of extended operation.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Buried and Underground Piping and Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In June 2013, the Independent Spent Fuel Storage Installation project relocated two hydrants and removed a buried manual isolation valve in the fire service system. The valve and adjacent ductile iron piping were visually inspected following removal. The valve riser had some accumulation of corrosion deposits, but no significant material loss was identified. Portions of the pipe wall external coating were removed to allow visual inspection of the pipe surface. The pipe surface was noted to be in good condition.
2. In May 2016, cathodic protection system testing did not meet the potential change criterion stipulated in station procedures. The probable cause of this condition was determined to be that the cathodic protection system was degraded and required installation of additional anodes. Specifically, the low potentials were attributed to insufficient cathodic protection current distribution, increased ground-bed resistances, and failure of ground-beds. It was also determined that the rectifiers' efficiency may have been reduced due to the age of the rectifiers. Further inspection identified anodes that required replacement due to low potential and also identified damage to rectifiers and wiring associated with the cathodic protection system. The necessary cathodic protection system maintenance and upgrades will be completed before the last five years of the inspection period prior to entering the subsequent period of extended operation.

3. In March 2020, cleaning and inspection was performed for the carbon steel emergency diesel generator (EDG) underground fuel oil storage tank 'A.' Ultrasonic testing (UT) examinations were performed on 25% of the tank wall. The minimum wall thickness specification for the tank shell is 0.312 inch. Most of the readings were around the nominal thickness (0.375 inch) in the gridding area with the lowest reading being 0.323 inch.
4. In March 2020, cleaning and inspection was performed for the carbon steel EDG underground fuel oil storage tank 'B.' UT examinations of the tank interior were performed on 25% of the tank wall. The minimum wall thickness specification for the tank shell is 0.312 inch. Most of the readings were around the nominal thickness (0.375 inch) in the gridding area with the lowest reading being 0.352 inch.
5. In September 2020, a visual inspection of coating on a four-inch carbon steel emergency diesel generator fuel oil storage tank buried pipe was performed. The coating was in fair condition with some areas of the outer coating layer (tape wrap) missing or damaged. However, the inner coating layer (coal tar enamel) was tightly adhered to the pipe and there was no evidence of the four-inch pipe surface being exposed to soil. No other issues or anamolies were noted during the inspection of the piping. There were no indications that required replacement of coating or remediation of piping.
6. In December 2020, as part of a site soil study, soil samples were obtained from 15 locations and analyzed. Data from the survey analyses were evaluated using the BPWORKS soil corrosivity index in EPRI Report 3002005294, “Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants.” Utilizing the EPRI BPWORKS index, two locations were determined to be mildly corrosive and 13 locations were moderately corrosive. In addition to soil samples obtained opportunistically during excavations, soil testing is conducted once in each ten-year period.
7. In July 2022, materials laboratory examination was conducted on five ring sections cut from three buried ductile iron fire service pipe segments. The examination focused on inspecting for evidence of selective leaching (graphitic corrosion) by grinding the cut faces of each sample flat to clean metal and examining for signs of pitting. The external surfaces of the ductile iron ring samples were free of any large deposits and rust blooms, showing only minor breaks in the form of rust spots in the asphaltic-based coating. The pitting noted on the outside diameter of the ring cross sections was mainly shallow and random. The maximum depth of pitting due to selective leaching was 0.093 inch, which indicates the components' intended function will be maintained based on the projected corrosion rate and measured extent of degradation.

8. In August 2022, materials laboratory examination was conducted on four gray cast iron samples cut from fire service hydrants/post indicating valves. The examination focused on inspecting for evidence of selective leaching (graphitic corrosion) by grinding the cut faces of each sample flat to clean metal and examining for signs of pitting. Each of the valve samples showed some degree of minor pitting. The majority of the pitting was observed on the internal surfaces. The degree of corrosion noted does not challenge the structural integrity of the valves or represent any long-term usage concerns under normal operating conditions. The overall condition of the valves was good.

The above examples of operating experience provide objective evidence that the *Buried and Underground Piping and Tanks* program includes activities to perform volumetric and visual inspections to identify loss of material for buried piping and tanks and underground bolting within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Buried and Underground Piping and Tanks* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Buried and Underground Piping and Tanks* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Buried and Underground Piping and Tanks* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.29 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Program Description

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is a new condition monitoring program that will manage loss of coating integrity of the in-scope components exposed to closed-cycle cooling water, raw water, and treated water environments, that can lead to loss of base materials or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings degrade and become debris. The program will manage loss of material or cracking for cementitious coatings/linings.

Periodic visual inspections will be conducted for each coating/lining material and environment combination of the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the component's or downstream component's intended function(s). Inspection intervals will not exceed those specified in NUREG-2191 Table XI.M42-1, Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers.

For tanks, heat exchangers, piping, and piping components, accessible surfaces will be inspected. Piping inspections will be sampling-based. If a baseline inspection has not been previously established, baseline coating/lining inspections will occur in the 10-year period prior to the subsequent period of extended operation. Subsequent inspection intervals will be established by a coating specialist qualified in accordance with ASTM International Standards endorsed in NRC Regulatory Guide (RG) 1.54, Revision 3, “Service Level I, II and III Protective Coatings Applied to Nuclear Power Plants,” including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications will be based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination are not acceptable. Blisters will be evaluated by a coatings specialist. Blisters are limited to a few intact small blisters that are completely surrounded by sound material and with the size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. Other degraded conditions will be evaluated by a coatings specialist. For coated/lined surfaces determined not to meet the acceptance criteria, the coating can be removed or physical testing performed, where physically possible (i.e., sufficient room to conduct testing), in conjunction with repair or replacement of the coating/lining.

In lieu of periodic inspections, opportunistic inspections will be performed as an acceptable alternative for buried internally coated/lined fire water system piping meeting the following three conditions:

1. Fire water system piping flow testing is performed consistent with Section 7.3.1 of NFPA 25, 2011 edition, “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” to determine the internal condition of the piping.

2. The water-based fire protection system is maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated.
3. A review of plant-specific operating experience has not identified any documented leaks due to the age-related degradation of the internal coatings used in the buried fire water system piping within the scope of subsequent license renewal.

NUREG-2191 Consistency

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” as modified by SLR-ISG-2021-02-MECHANICAL, "Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance."

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. During the Spring 2011 refueling outage (RF19), an inspection of the 'A' component cooling water heat exchanger noted coating damage in one area in the west end tubesheet. Coating damage to the east end tubesheet had been previously noted during a post hydrolase inspection, attributable to improper repairs from Fall 2009. Incorrect guidance for coating application was determined to be the probable cause. The coating application procedure was revised in November 2009 to provide accurate guidance for the proper application of coatings and the repairs were completed in May 2011 utilizing the updated procedure.
2. During the Spring 2017 refueling outage (RF23), an inspection of the condensate storage tank identified several areas of rust (corrosion) on the internal tank wall. The area was small and identified as minor surface rust with no signs of any significant degradation. Corrosion was observed on less than 1% of the internal surface area. No significant pitting was observed. Areas where pitting occurred were within the tolerance of the coating dry film thickness. Minor blistered areas were observed on the floor within one to two feet of the shell wall and lower shell course. Several blisters were removed, which revealed smooth base metal.

Ultrasonic testing (UT) examinations were performed on the tank bottom plates and the air to water interface on the side walls. Based on a review of the results, Engineering concluded that the tank bottom and side wall thickness measurements were satisfactory.

The internal coating was observed to be in very good condition with no flaking or chipping identified. Minor coating repairs were performed in May 2017.

3. During the Spring 2017 refueling outage (RF23), degraded coating conditions were identified during inspection of the 'A' component cooling water heat exchanger. Multiple areas of coating damage were identified on the heat exchanger east end inlet tubesheet and the west end inlet and outlet tubesheets. None of the identified locations were severe enough to expose the base carbon steel tubesheet. Coating repairs were completed in May 2017.

The above examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program will include activities to perform visual inspections of internal surfaces to identify loss of coating integrity for piping, piping components, heat exchangers and tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program will effectively manage aging prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.30 ASME Section XI, Subsection IWE

Program Description

The *ASME Section XI, Subsection IWE* program is an existing condition monitoring program that manages cracking, loss of leak tightness, loss of material, loss of preload, and loss of sealing of the steel liner of the concrete Containment. *ASME Section XI, Subsection IWE* program inspections are performed in order to identify and manage containment liner aging effects that could result in loss of intended function for the subsequent period of extended operation. Included in this inspection program are the airlocks, containment liner plate and its integral attachments, containment penetrations, containment hatches, moisture barriers, and pressure-retaining bolting.

Surface and volumetric examinations are performed to identify indications of degradation. The primary inspection method is visual examination (general visual, VT-1, VT-3) of surfaces for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities, including discernible liner plate bulges. Limited volumetric examinations (ultrasonic thickness measurement) and surface examinations (e.g., liquid penetrant) are performed, as required. Acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found are in accordance with ASME Code, Section XI, Subsection IWE, Article IWE 3000.

For the third containment inspection interval, beginning during the first quarter of 2017, IWE containment inservice inspections are performed in accordance with ASME Code, Section XI, Subsection IWE, 2007 Edition (through the 2008 addenda). In conformance with Title 10 of the Code of Federal Regulations (10 CFR) 50.55a(g)(4)(ii), the *ASME Section XI, Subsection IWE* program will be updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the ASME Code specified 12 months before the start of the inspection interval.

Using the guidance in NRC Information Notice 14-07 (IN 14-07),“Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner,” the Containment basement slab liner leak chase channel test connections are regarded as 'Moisture Barriers', and the accessible areas are subject to general visual examinations in accordance with ASME Code, Section XI, Subsection IWE, Table IWE 2500-1, Examination Category E-A, Item E1.30.

Procedures and specifications include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload. There are no ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts) identified within the scope of the *ASME Section XI, Subsection IWE* program.

There are no two-ply penetration bellows installed as part of the containment pressure boundary. Stainless steel high energy pipes that penetrate the Containment are connected to penetration sleeves with dissimilar metal welds. Plant-specific operating experience has not identified any stress corrosion cracking associated with these welds.

The *ASME Section XI, Subsection IWE* program visual examinations will be supplemented with one-time surface examinations (or other applicable technique, e.g., EVT-1) to manage cracking due to SCC for stainless steel and dissimilar metal welds in the Containment pressure-retaining portions of the fuel transfer tube assembly and high-temperature piping penetrations. The supplemental surface examinations will be one-time inspections that will be performed before entering the subsequent period of extended operation. A representative sample size of 20% of the population of stainless steel penetrations and dissimilar metal welds associated with penetrations for high operating temperature piping systems will be subject to the one-time supplemental surface examinations. Additionally, a one-time volumetric examination of metal liner surfaces that are inaccessible from one side will be performed, if triggered by plant-specific operating experience. This supplemental volumetric examination will consist of a sample of one-foot square locations that includes both randomly-selected and focused areas most likely to experience degradation based on operating experience and/or relevant considerations such as environment.

The *ASME Section XI, Subsection IWE* program manages aging of the steel liner of the concrete Containment. The *10 CFR Part 50, Appendix J* program (B2.1.33) manages loss of leak tightness, loss of sealing, and leakage through Containment. Containment seals and gaskets are included in the scope of the *10 CFR Part 50, Appendix J* program (B2.1.33). An evaluation of the acceptability of the inaccessible areas is completed whenever conditions are detected in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

A review of 10 years of plant-specific operating experience associated with inaccessible areas from the *ASME Section XI, Subsection IWE* program did not identify any significant indications of Containment liner corrosion.

Service Level 1 coatings are included in the scope of the *Protective Coating Monitoring and Maintenance* program (B2.1.37).

The *ASME Section XI, Subsection IWE* program is implemented as a Fleet program at Dominion. The Fleet program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *ASME Section XI, Subsection IWE* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S1, “ASME Section XI, Subsection IWE,” as modified by SLR-ISG-2021-03-STRUCTURES, "Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Parameters Monitored / Inspected (Element 3); Detection of Aging Effects (Element 4); and Acceptance Criteria (Element 6)

1. Procedure(s) will be revised to require one-time supplemental surface examinations (or other applicable technique; e.g., EVT-1) to detect cracking due to SCC of the Containment pressure-retaining portions of the stainless steel fuel transfer tube assembly and 20% of the stainless steel or dissimilar metal welds associated with high temperature piping penetration sleeves, (i.e., penetration sleeves with temperatures greater than or equal to 140 degrees F). The one-time supplemental surface examinations will be performed prior to the subsequent period of extended operation to confirm the absence of cracking due to SCC. If SCC is detected as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the Corrective Action Program.

Detection of Aging Effects (Element 4)

2. Procedure(s) will be revised to require a one-time volumetric examination of metal liner surfaces that are inaccessible from one side, only if triggered by plant-specific operating experience. The trigger for this supplemental examination will be plant-specific occurrence or recurrence of measurable metal liner corrosion (base metal material loss exceeding 10% of nominal plate thickness) on the inaccessible side or areas, identified since the date of issuance of the initial renewed license. This supplemental volumetric examination will consist of a sample of one-foot square locations that include both randomly-selected and focused areas most likely to experience degradation based on operating experience and/or other relevant considerations such as environment. This supplemental volumetric examination will occur within two refueling outages after identifying the triggering for the examination. Any identified degradation will be addressed in accordance with the applicable provisions of the *ASME Section XI, Subsection IWE* program. The sample size, locations, and any needed scope expansion (based on findings) for the supplemental volumetric examinations will be

determined on a plant-specific basis to demonstrate statistically with 95% confidence that 95% of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than 10% loss of nominal thickness. There has been no triggering operating experience for liner corrosion since the date of issuance of the initial renewed license.

Monitoring and Trending (Element 5)

3. Procedure(s) will be revised to specify that successive inspections be sequenced, evaluated, and re-examined in accordance with ASME Code, Section XI, Subsection IWE, Article IWE-2420. Examination results will be compared with recorded results of prior inservice examinations and evaluated for acceptance in accordance with ASME Code, Section XI, Subsection IWE, Article IWE-3120.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWE* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2011, it was identified that visual examinations of accessible parts of the containment liner floor plate leak-chase systems were not being performed in accordance with ASME Code, Section XI, Subsection IWE requirements. Visual examinations were performed of the 51 test connection plugs; four were found with missing tube plugs, with debris in the tubing, water inside the channels, and minor indications of corrosion were evident. Pressure drop tests were conducted for each of these four leak-chase channel zones. Leakage measurements were acceptable, indicating confidence in the overall leak-tightness of the liner weld areas. The corrective actions included replacing the missing closure plugs and filling the remaining floor test connection boxes with epoxy grout and sealant to preclude leakage through the test connections into the floor liner areas below these connections. In addition, procedures were revised to require inspection of the floor leak-chase junction box area and test connection closure or sealing as part of the ASME Section XI, Subsection IWE inspections. This containment liner floor leak-chase operating experience is also addressed in NRC Information Notice 2014-07. Following the issuance of Information Notice 2014-07, the scope and completeness of the population of leak-chase test connections and closure plugs was reassessed. In 2017, one additional test connection plug was found missing from a leak-chase channel on the liner wall above the concrete basement slab in a partially obscured location. The interior of that channel and the associated liner were inspected by remote camera with satisfactory results. Engineering evaluated the condition as acceptable. Inspection procedures and drawings were revised to specifically clarify the requirements and scope of the required inspections.

2. In June 2011, during the *ASME Section XI, Subsection IWE* program general visual examinations, groundwater intrusion, coating degradation and corrosion of residual heat removal and reactor building spray penetration guard pipes in the Auxiliary Building were noted.

   Four residual heat removal and reactor building spray isolation valves located in the Auxiliary Building are enclosed within steel chambers. The steel chambers are connected by guard pipes through penetration sleeves in the Auxiliary Building wall to the four residual heat removal and reactor building spray system recirculation sumps in the Reactor Building. These isolation valve chambers and the guard pipes are an extended part of the Containment pressure and leakage boundary.

   Similar observations of groundwater intrusion, coating degradation, and corrosion of the guard pipes were noted in previous examinations, and as a result, more frequent augmented examinations of the residual heat removal and reactor building spray penetration guard pipes were begun under the Containment ISI *ASME Section XI, Subsection IWE* program. Additionally, a dewatering system was installed in 2008 which reduced, but did not completely eliminate, the groundwater intrusion into these guard pipe penetration areas.

   The *ASME Section XI, Subsection IWE* program has continued to monitor the condition of the guard pipes during more frequent augmented examinations since 2011. Ultrasonic testing (UT) wall thickness measurements were obtained and utilized by Engineering to project the degradation rate to ensure the design function of the guard pipes would be maintained until the next scheduled inspection. The nominal wall thickness of the guard pipes is 0.5-inches. General area wall thickness measurements have typically averaged greater than 0.48-inches, with local pitting measurements slightly less. Engineering determined the minimum wall thickness for local pitting is 0.25-inches, and for general surface area is 0.35-inches. There is a wide margin between the wall thicknesses measured during the inspections and the required minimum thicknesses which provides assurance that the design function will be maintained.

   In 2021, the residual heat removal and reactor building spray guard pipes were prepared and recoated with a coating product selected to provide optimal performance in damp or moist service conditions. Engineering selected this product based on manufacturers information and site-specific testing. Engineering expects much better performance and protection from this product in comparison to previous coatings.

   The condition of the residual heat removal and reactor building spray guard pipes are currently monitored during more frequent augmented examinations which occur each refueling outage under the *ASME Section XI, Subsection IWE* program. In addition, the pressure boundary integrity of residual heat removal and Reactor Building spray valve chambers and guard pipes are monitored during Appendix J, Type B local leak rate testing. At least two of the four guard pipes are leakage tested during each refueling outage in accordance with plant procedures.

3. In May 2014, an 8-inch long crack in the coating over a fillet weld with a small rust trail indication was identified during the *ASME Section XI, Subsection IWE* program inspections. The crack in the coating was located over the fillet weld connecting an 8-inch diameter attachment plate to the thickened reinforcement liner insert plate surrounding a 42-inch diameter pipe penetration. The defective coating was removed. Liquid dye penetrant examination was performed on the weld which was found acceptable with no indications. The local area was prepared, and the local area was recoated with a qualified coating. The fillet weld which had the coating crack above it, is not part of the containment pressure boundary but serves to connect the attachment plate to the thickened penetration insert plate which is part of the containment pressure boundary. The Reactor Building is examined for defective coatings during each refueling outage. The coatings and liner examinations look for small coatings defects which could mask underlying corrosion of Containment liner pressure boundary items or items welded to the containment pressure boundary.
4. In May 2014, surface wear indications were found on the Reactor Building personnel access hatch during *ASME Section XI, Subsection IWE* program visual examinations. Engineering performed an evaluation of these conditions and determined the conditions acceptable since there was no impact on the capability of the doors to engage the latch when closed and to hold the door securely closed, and these conditions did not impact the capability of the airlock to perform its design basis containment function. The door successfully passed the Appendix J, local leak rate testing ensuring required function and sealing.
5. In May 2016, Engineering evaluated NRC Regulatory Issue Summary (RIS) 2016-07, “Containment Shell or Liner Moisture Barrier Inspection”. It was determined that the ASME Section XI, Subsection IWE examinations and associated procedures for the Containment liner moisture barrier address the inspection scope for moisture barriers described in RIS 2016-07. The moisture barrier seal is currently addressed as an augmented examination requiring 100% examination each outage because during previous inspections mechanical damage to the sealant or debond of the sealant from the liner has been observed at some locations. In each case where moisture barrier deficiencies were identified, necessary maintenance corrective actions were taken to rework the seal and return the identified locations to design conditions.
6. In October 2019, an independent assessment of the implementation of initial license renewal programs and commitments was conducted. The assessment report concluded that the ASME Code, Section XI, Subsection IWE program portion of the Containment ISI aging management program has been implemented as required with only a minor FSAR update to be performed. Completion of the FSAR update is tracked in the Corrective Action Program.

7. In April 2020, during the refueling outage, the Containment moisture barrier was found damaged after moisture barrier repairs were performed. A separation between the liner and the moisture barrier 1.5-inches long was identified at approximately 145 degrees. Also noted nearby was an 8-inch long area in the moisture barrier that is recessed approximately ¼-inch below the floor level. After the sealant was removed the inspector observed evidence of surface corrosion on the Reactor Building liner exposed surface at both locations. Visual and ultrasonic thickness measurement examinations were performed in these areas; the seal areas were reworked to restore design conditions and the results of the examinations were evaluated as satisfactory by the responsible engineering individual.

The above examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWE* program includes activities to perform visual examinations (general visual, VT-3, VT-1) and limited volumetric examinations (ultrasonic thickness measurement) to identify cracking, loss of leak tightness, loss of material, loss of preload, and loss of sealing for the containment liner plate and its integral attachments within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the ASME Section XI, Subsection IWE program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME Section XI, Subsection IWE* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI, Subsection IWE* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.31 ASME Section XI, Subsection IWL

Program Description

The *ASME Section XI, Subsection IWL* program is an existing condition monitoring program that manages the following aging effects for Containment concrete and the unbonded post-tensioning system:

- Cracking
- Cracking; loss of bond; and loss of material (spalling, scaling)
- Cracking; loss of material
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material (spalling, scaling) and cracking
- Loss of material
- Loss of prestress

The *ASME Section XI, Subsection IWL* program tests selected sample tendons for tendon prestressing force, and selected tendon wires for yield strength, ultimate tensile strength, and elongation consistent with the ASME Code, Section XI, Subsection IWL requirements and station procedures. The sample tendons include hoop tendons, vertical tendons and dome tendons. Tendon grease is analyzed for alkalinity, water content, and soluble ion concentrations. The assessment and trending of measured tendon prestressing forces is performed in accordance with station procedures and ASME Code, Section XI, Subsection IWL requirements.

For the third Containment inspection interval, beginning during the first quarter of 2017, IWL Containment Inservice Inspections are performed consistent with the 2007 Edition of ASME Code, Section XI, Subsection IWL (including 2008 addenda), supplemented with the applicable requirements of 10 CFR 50.55a(b)(2). In conformance with 10 CFR 50.55a(g)(4)(ii), the *ASME Section XI, Subsection IWL* program will be updated during each successive 120 month inspection interval to comply with the requirements of the latest edition and addenda of the ASME Code specified 12 months before the start of the inspection interval.

The program includes the accessible areas of the Containment concrete dome and cylinder walls. When conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas, the conditions are evaluated to determine the acceptability of such inaccessible areas. The primary inspection method is visual examination (general visual, detailed visual), supplemented by testing. Visual examinations of concrete use the evaluation criteria provided in Chapter 5 of American Concrete Institute (ACI) 349.3R, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.” 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, “Guide for Conducting a Visual Inspection of Concrete in Service.”

Plant procedures specify quantitative acceptance criteria for concrete surfaces that are consistent with the ACI 349.3R Chapter 5 ‘second-tier’ acceptance criteria. The Responsible Engineer evaluates inspection results that do not meet established acceptance standards to ensure that corrective action is implemented before loss of intended functions.

Concrete inspectors are trained to identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program, the *Structures Monitoring* program (B2.1.35), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.36).

The *ASME Section XI, Subsection IWL* program is implemented as a Fleet program at Dominion Energy. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196), and determinations were made for each station that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *ASME Section XI, Subsection IWL* program is an existing program that is consistent with NUREG-2191, Section XI.S2, 'ASME Section XI, Subsection IWL.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWL* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In July 2011, a five-year *ASME Section XI, Subsection IWL* program examination of selected unbonded post-tensioning tendons was performed. The minimum sample wire elongation determined by testing is required to be 4%. Individual sample wire elongation tests were

performed as required. The elongation at ultimate tensile test failure of six of the original nine individual wire test samples was less than the 4% acceptance criteria. The average of the nine samples was 3.84%. Additional confirmation wire samples were also tested and seven of the additional nine test results were also less than 4%. The individual wire tensile test results which include the wire elongation test results were evaluated by the IWL Responsible Engineer and found to be acceptable. The IWL Responsible Engineer reviewed the previous individual wire elongation tests and found the 2011 results were consistent with the range of test result scatter expected for these wire samples based on past surveillances. Engineering concluded there was no change or trend in the wire elongation test values. Engineering evaluated the tendon and wire test results and concluded there was no indication of abnormal degradation of the wire or prestress system. Ultimate tensile strength and yield strength acceptance criteria for the wire tensile testing were met for the samples. The other surveillance tests and examinations conducted on the surveillance tendons were also satisfactory including tendon liftoff force and tendon elongation. The engineering evaluation also considered the configuration and length of the tendons and assessed design elongation requirements in comparison with the elongation values measured and concluded a substantial margin exists for wire ductility.

2. In October 2015, during the performance of the Containment tendon inspections, one sample tendon failed to meet the evaluation criteria for average measured liftoff force equal to, or greater than, 95% of the predicted tendon liftoff force. The measured liftoff forces for eight of the nine surveillance tendons were found to be above the 95% of predicted lift off force criteria. The average liftoff force of the one sample tendon that failed the initial criteria was 93.7% of the average predicted liftoff force. In accordance with ASME Code, Section XI, Subsection IWL requirements and the approved station procedure, liftoff forces were also measured for the two tendons adjacent to the one tendon found with the liftoff test result slightly lower than the 95% of the predicted liftoff force criteria. The two additional tendons tested were both found to have liftoff forces greater than the 95% of average predicted liftoff force criteria. The procedural evaluation required for this tendon determined that the tendon was satisfactory as it met the criteria of greater than 90% of the predicted liftoff force, and the additional criteria that the additional tendons tested had liftoff test values greater than the 95% of average predicted liftoff force criteria. The group average liftoff force for the as-found liftoff values as well as the individual liftoff values during this surveillance were above the required average minimum design forces for the respective tendon group and are therefore acceptable. The trend analysis results using the current as well as previous liftoff data show the tendon groups forces staying above the required minimum design force beyond the next regularly scheduled surveillance. The responsible engineer evaluated the conditions identified and determined the tendon liftoff forces were acceptable.

3. In October 2015, during the performance of the Containment tendon inspections, one tendon was found with several of the 170 wires protruding from the anchorage ends by small amounts. Continuity testing and assessment performed on protruding wires determined the wires were not broken. Engineering evaluated these conditions and concluded that because tendon wire bundles are fabricated and installed with a number of twists in the wire bundle that when the tendon is placed in a deflected location such as for a hoop or dome tendon, in some cases, the wire is held by frictional forces within the wire bundle from completely seating on the anchor head. In such cases, the protruding wire is considered fully effective and carries the same prestress force as the other wires in the tendon bundle if continuity has been determined. These conditions were evaluated by engineering and determined to be acceptable.
4. In October 2019, an independent assessment of the implementation of initial license renewal programs and commitments was conducted. The assessment report concluded that the *ASME Section XI, Subsection IWL* program has been implemented as required with only a minor recommended FSAR update remaining. Completion of this document update is tracked as a Corrective Action Program action.
5. In May 2020, immediately prior to and during the refueling outage, the ASME Section XI, Subsection IWL examinations of the Containment concrete and prestress tendon system were performed. No reportable items or items indicative of abnormal degradation were identified by the IWL inspections for the following:
   - Augmented inspection of the tendon access gallery
   - 40th Year surveillance of prestress tendon system
   - General visual examination of exterior concrete surfaces of the containment structure

   One horizontal tendon was found upon removal of the grease cap with one wire protruding from the anchorage end. The condition of the wire protrusion was evaluated by engineering, and the condition was determined to be acceptable.

   The results of the prestress tendon system examinations and tests were evaluated and summarized by the Responsible Engineer as follows:

   - The measured liftoff forces for the surveillance tendons were found to be above 95% of the predicted lift off force values as required.
   - The required surveillance and test criteria for the tendons including tendon force and elongation, wire samples inspection and testing, grease samples testing for water and impurities, tendon anchorage hardware and adjacent concrete areas, and corrosion protection grease were acceptable.

- The regression (trend) analysis results using the current as well as previous liftoff data show forces for each of the groups staying above the required minimum design force beyond the next regularly scheduled surveillance.
- The responsible engineer also reported a forecast for when the prestress group mean may fall below design minimum average prestress. Prestress group mean results are expected to remain at or above design minimum average values until after 2074 for dome tendons, and after 2100 for hoop and vertical tendons.

The above examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWL* program includes activities to perform visual examinations (general visual, detailed visual), supplemented by testing to manage aging effects for containment concrete and unbonded post-tensioning system components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *ASME Section XI, Subsection IWL* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME Section XI, Subsection IWL* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI, Subsection IWL* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.32 ASME Section XI, Subsection IWF

Program Description

The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that manages cracking, loss of material, loss of mechanical function, and loss of preload for ASME Classes 1, 2, 3, and MC piping and components supports.

During the fourth inservice inspection interval (January 1, 2014 through December 31, 2023), inspections of supports for Class 1, 2, 3, and MC piping and components are performed consistent with ASME Code, Section XI, 2007 Edition through 2008 Addenda, as incorporated in 10 CFR 50.55a. In conformance with 10 CFR 50.55a(g)(4)(ii), the Inservice Inspection program is updated during each successive 120-month inspection interval to comply with the requirements of the edition and addenda of the Code that is applicable twelve months before the start of the inspection interval. ASME Code editions and addenda will be used consistent with the provisions of 10 CFR 50.55a during the subsequent period of extended operation.

Supports for Class 1, 2, 3, and MC piping and components are selected for examination per the requirements of ASME Code, Section XI, Subsection IWF. Acceptance standards are specified in ASME Code, Section XI, Subsection IWF, Subarticle IWF-3400. The scope of the inspection for supports is based on class and total population as defined in Table IWF-2500-1. When a component support requires corrective measures in accordance with the provisions of Article IWF-3000, that support is re-examined during the next inspection period. When the reexaminations do not require additional corrective measures during the next inspection period, the inspection schedule reverts to the requirements of the original inspection program.

Component support examinations that detect flaws or relevant conditions exceeding the acceptance standards of ASME Code, Section XI, Subsection IWF, Subarticle IWF-3400 are extended to include additional examinations in accordance with ASME Code, Section XI, Subsection IWF, Subarticle IWF-2430. The *ASME Section XI, Subsection IWF* program provides a systematic method for periodic examination of supports for Class 1, 2, 3, and MC piping and component supports. The primary inspection method is visual examination. Procedures include instructions and acceptance standards for the visual examinations (VT-3).

If a component support does not exceed the acceptance standards of ASME Code, Section XI, Subsection IWF, Subarticle IWF-3400, but is electively repaired to as-new condition, then the sample will be increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

Procedures include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying 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. For structural bolting consisting of ASTM A325 and ASTM A490 bolts, preventive actions for storage, lubricant selection, and bolting and coating material selection will be consistent with Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts.” Twist-off type ASTM F1852 and ASTM F2280 bolts are not specified or stocked for use.

This program will include a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation.

The *ASME Section XI, Subsection IWF* program is implemented as a Fleet program at Dominion Energy. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196), and determinations were made for each station that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *ASME Section XI, Subsection IWF* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.S3, “ASME Section XI, Subsection IWF.”

Exception Summary

The following program element(s) are affected:

Parameters Monitored / Inspected (Element 3) and Detection of Aging Effects (Element 4)

1. NUREG-2191 requires volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 to be performed on a sample of high-strength bolting [actual measured yield strength greater than or equal to 150 ksi (1,034 MPa)] in sizes greater than 1-inch nominal diameter at least once per interval to detect cracking in addition to the VT-3 visual examination. NUREG-2191 also states that this volumetric examination may be waived with plant-specific justification. The high-strength bolts greater than 1-inch nominal diameter are ASTM A490, installed in Class 1 supports, and the necessary conditions for the development of stress corrosion cracking (SCC) do not exist. Therefore, the program takes exception to the requirement to perform augmented examinations of high-strength bolting greater than 1-inch nominal diameter.

Justification for Exception

The high-strength bolts greater than 1-inch nominal diameter within the scope of the IWF program are ASTM A490, installed in Class 1 supports. The potential for SCC for the in-scope ASTM A490 bolts and the potential need to augment ASME Section XI, Subsection IWF ISI examinations for such bolts was previously evaluated by the NRC during the initial license renewal review process.

As indicated in Section 3.5.2.3.3 of the NRC Safety Evaluation Report for initial license renewal, NUREG-1787 (ADAMS Accession No. ML041040070), SCC is not considered an aging mechanism requiring management based on the following:

- ASTM A490 anchor bolt material was properly heat-treated by conforming to ASTM Specification A490 through a certified mill test report.
- Anchor bolts are tightened snug-tight as defined by AISC; therefore, for bolts greater than 1 in diameter, a significant preload (in the order of 70% of ultimate strength) is not practical to develop.
- Anchor bolts do not have a high level of sustained tensile stress as evidenced by lower faulted condition design loads due to elimination of dynamic effects subsequent to postulated High Energy line Break (HELB) of the reactor coolant system primary coolant piping.

In summarizing the applicability of SCC of high-strength bolts, the SER maintains, “On the basis that (1) the necessary conditions for the development of SCC in high strength bolts do not exist at VCSNS and (2) there has been no plant-specific operating experience related to SCC of high strength bolts, the staff finds that augmented inspection for SCC of high strength bolts used in Class 1 supports is not warranted; inspection of Class 1 supports to the requirements of ASME Code, Section XI, Subsection IWF, is judged to be sufficient to manage aging for the period of extended operation.”

In addition, Table 2-9 in NUREG-2221, “Technical Bases for Changes in the Subsequent License Renewal Guidance Documents NUREG-2191 and NUREG-2192,” indicates ASTM A490 bolts used in civil structures have not shown to be prone to SCC. Thus, the potential for SCC need not be evaluated for these bolts.

A review of operating experience since 2003 did not identify any issues related to SCC of high-strength bolts.

Based on the above, augmented examinations are not needed and the existing *ASME Section XI, Subsection IWF* program will continue to adequately manage the effects of aging so that the intended functions of high-strength bolting will be maintained during the subsequent period operation.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedure(s) will be revised to include class MC component supports in the scope of the program.
2. Procedure(s) will be revised to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

Preventive Actions (Element 2)

3. Procedure(s) will be revised to require ASTM A325 and ASTM A490 bolts and associated nuts and washers to be stored in closed containers to protect them from dirt and corrosion. Additionally, the closed containers will be required to be stored in a protected shelter (Storage Level B or C) until use.

Detection of Aging Effects (Element 4)

4. Procedure(s) will be revised to specify a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation.

Monitoring and Trending (Element 5)

5. Procedure(s) will be revised to require that if a component support does not exceed the acceptance standards of IWF-3400 but is repaired to as-new condition, the sample will be increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

Acceptance Criteria (Element 6)

6. Procedure(s) will be revised to include the additional unacceptable conditions indicated below.
    a. Loss of material due to corrosion or wear.
    b. Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support.
    c. Cracked or sheared bolts, including high-strength bolts, and anchors.
    d. Cracks.

The above conditions may be accepted provided the technical basis for their acceptance is documented.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWF* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2012, during an outage closeout walkdown, a nut and bolt on the control rod drive mechanism (CRDM) cable bridge connection to the support beam were discovered missing. A bolt attaching the missile shield wall bracket to the top of the missile shield was protruding and did not appear fully tightened, and a gap was identified between the missile shield wall bracket and the wall. The nut and bolt missing from the CRDM cable bridge connection to the support beam were re-installed. The bolt attached to the missile shield wall bracket was reworked. The gap between the missile shield wall bracket and wall were repaired the following outage.
2. In 2013, it was identified that the reactor vessel supports were not included in the ASME Code, Section XI, Inservice Inspection Program. The reactor vessel steel support structures were previously considered to be inaccessible since they are mostly embedded or encased in concrete; and there is no access for a direct general visual inspection. Additionally, technology at the time of construction and early operation was considered inadequate for an acceptable remote visual inspection of these supports. In 2015, a remote visual examination of the accessible portion of the steel supports was performed with satisfactory results. The examinations were performed through air vent channels located on the left and right side of each support and were limited to the bottom section of the support assembly due to accessibility. These supports were also added to the list of ASME Code, Section XI, Inservice Inspection Program inspections.
3. In 2018, a visual examination of a residual heat removal piping spring hanger support found two jam nuts loose. Engineering determined the piping spring hanger support was fully able to perform its design function, and the loose jam nuts were tightened. The piping spring hanger support satisfied the other acceptance standards of the ASME Code, Section XI, Subsection IWF.
4. In 2020, during inservice inspections a pipe support strut for the residual heat removal system was found out of alignment and a jam nut was loose. This deficiency was evaluated by Engineering and determined as having no impact on the ability of the support to perform its design function. The pipe clamp was re-aligned and the jam nut was tightened.

5. In 2021, results of an internal audit of the Inservice Inspection, Inservice Testing and Appendix J programs concluded the programs were effectively implemented. There were no findings or recommendations as a result of the audit.

The above examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWF* program includes activities to perform visual examinations (VT-3) to manage cracking, loss of material, loss of mechanical function, and loss of preload for ASME Classes 1, 2, and 3 piping and components supports within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *ASME Section XI, Subsection IWF* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME Section XI, Subsection IWF* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI, Subsection IWF* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.33 10 CFR Part 50, Appendix J

Program Description

The 10 CFR Part 50, Appendix J program is an existing performance monitoring program that manages cracking, loss of leak tightness, loss of material, loss of preload and loss of sealing. Leakage rates through the Containment pressure boundary are monitored, including the Containment 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.

Leakage rate testing is performed in accordance with the regulations and guidance provided in 10 CFR Part 50, Appendix J, Option B; and NEI 94-01, Revision 2-A, “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J.”

Containment leak rate tests are performed to verify that leakage through the Containment, and systems and components penetrating the Containment, remains below Technical Specification allowable limits. An integrated leak rate test is performed during unit shutdown at an interval based on the historical performance of the overall Containment system. A general visual inspection of accessible interior and exterior surfaces of the Containment structure is conducted at intervals that comply with Appendix J to Title 10 of the Code of Federal Regulations (10 CFR) Part 50. Local leak rate tests are performed on Containment access penetrations and Containment isolation valves at intervals that comply with 10 CFR Part 50, Appendix J, Option B.

Visual inspections of the accessible interior and exterior surfaces of the Containment structure and components, performed by the *ASME Section XI, Subsection IWE* program (B2.1.30) and the *ASME Section XI, Subsection IWL* program (B2.1.31), augment the *10 CFR Part 50, Appendix J* program leakage rate testing and detect evidence of structural degradation that may affect the Containment structure leakage integrity.

The aging effects associated with the Containment pressure boundary components within the scope of subsequent license renewal and excluded from Type B or C Appendix J local leak rate testing are managed by the following aging management programs:

- *Water Chemistry* program (B2.1.2)
- *Flow-Accelerated Corrosion* program (B2.1.8)
- *Closed Treated Water Systems* program (B2.1.12)
- *Compressed Air Monitoring* program (B2.1.14)
- *Fire Water System* program (B2.1.16)
- *One-Time Inspection* program (B2.1.20)

- *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25)
- *ASME Section XI, Subsection IWE* program (B2.1.30)
- *Environmental Qualification of Electric Equipment* program (B3.3)

NUREG-2191 Consistency

The *10 CFR Part 50, Appendix J* program is an existing program that is consistent with NUREG-2191, Section XI.S4, “10 CFR Part 50, Appendix J.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *10 CFR Part 50, Appendix J* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2011, a Reactor Building recirculation sump isolation valve failed Type C LLRT. After Motor-Operated Valve Analysis and Test System (MOVATS) testing was performed satisfactorily, the valve stem packing was adjusted and the valve was retested satisfactorily. The associated Type B test was subsequently performed with a satisfactory leak rate.
2. In May 2011, the Reactor Building spray sump isolation valve 'A' exceeded the surveillance limit during post-maintenance Type C LLRT. In April 2011, the as-found Type B penetration leak rate was acceptable. The valve was retested and the as-left valve Type C leakage was satisfactory.
3. In October 2012, the 30-day water seal test on the 'B' residual heat removal pump suction isolation valve from reactor coolant system loop 'C' penetration was unsatisfactory. This isolation valve is not normally subject to Type C testing due to the column of water submerging the valve seat. Failure of the water seal test requires performance of a Type C LLRT. The LLRT result exceeded surveillance acceptance limit. The Engineering evaluation required that as-found conditions be replicated to the extent possible prior to performing the post-LLRT. The subsequent post-LLRT on the isolation valve measured satisfactory leakage.
4. In March 2013, during the performance of Type B LLRT for the Reactor Building recirculation sump, excessive leakage was measured. Troubleshooting indicated the body of the relief valve for Reactor Building spray sump isolation valve 'B' was leaking. The relief valve was

repaired and retested satisfactorily. Engineering determined the relief valve (and subsequently the chamber) would have been operable for the required 30-day mission time.

5. In April 2014, containment isolation valve Type C LLRT on a fire service supply header check valve failed. Mechanics removed the check valve bonnet and performed an inspection. The check valve internals were satisfactory, but the area around the valve seat was dirty. The mechanics cleaned the disc/seat area and the bonnet gasket area. The post-LLRT on the check valve had a satisfactory leak rate. The failure was attributed to corrosion/dirt buildup on the seat.

6. In April 2017, Type C LLRT leakage on a Reactor Building sprinkler system supply header isolation valve was above the surveillance acceptance limit. The valve was cleaned and inspected and the cause of the leakage was assessed to be corrosion and debris. A satisfactory post-LLRT was performed.

7. In October 2018, a Type A ILRT using the ANSI/ANS-56.8 mass point data analysis technique was conducted. The as-left leakage rate result, including Type B and C penalty additions and containment volume correction, was acceptable.

   Leakage savings were realized when repairs and adjustments to Type B and C tested components were completed during the Type A test outage. The calculated leakage savings were added to the as-left result to obtain the as-found result which was acceptable.

8. In 2021, results of an internal audit of the Inservice Inspection, Inservice Testing and Appendix J programs concluded the programs were effectively implemented. There were no findings or recommendations as a result of the audit.

The above examples of operating experience provide objective evidence that the *10 CFR Part 50, Appendix J* program includes visual inspections and leak rate tests to identify cracking, loss of leak tightness, loss of material, loss of preload, and loss of sealing for Containment pressure boundary components, including the liner, penetrations, associated welds, access openings, seals, and gaskets within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *10 CFR Part 50, Appendix J* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *10 CFR Part 50, Appendix J* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *10 CFR Part 50, Appendix J* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.34 Masonry Walls

Program Description

The *Masonry Walls* program is an existing condition monitoring program that manages cracking, loss of material, and loss of material (spalling and scaling) for masonry walls. The *Masonry Walls* program is implemented as part of the implementing procedure for the *Structures Monitoring* program (B2.1.35).

NRC Inspection and Enforcement Bulletin (IEB) 80-11, regarding maintaining reasonable assurance that the evaluation basis and structural condition for masonry walls are maintained in order to prevent wall failure or wall attachment failure from adversely affecting a safety-related system, did not apply to VCSNS. Masonry walls do not exist inside of safety-related structures. NRC Information Notice 87-67 (IN 87-67) recommends plant-specific condition monitoring of masonry walls and administrative controls to ensure that modification, reclassification or newly installed walls are evaluated consistent with bulletin requirements. Consistent with the IN 87-67 guidance, the site inspection program was updated to specifically include a new, seismically designed, reinforced masonry wall that is outdoors, near a safety-related component, which is further discussed in the operating experience review. Design change procedures require consideration of appropriate attributes for changes involving masonry walls and for safety-related systems or component to be located nearby or attached to masonry walls.

The *Masonry Walls* program will consist of inspections 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.

The *Masonry Walls* program relies on periodic visual inspections which will not exceed five years, to monitor and maintain the condition of masonry walls within the scope of subsequent license renewal so that the established evaluation basis of each masonry wall remains valid during the subsequent period of extended operation.

The *Masonry Walls* program inspections are conducted by qualified personnel.

Masonry wall inspections are performed and results evaluated consistent with applicable industry documents to ensure that a loss of intended function does not occur. Conditions found to impact the intended function of the masonry wall or invalidate its evaluation basis are entered into the Corrective Action Program.

Masonry walls that are considered fire barriers are also managed by the *Fire Protection* program (B2.1.15). Structural steel bracing and edge supports associated with masonry walls are visually inspected by the *Structures Monitoring* program (B2.1.35).

NUREG-2191 Consistency

The *Masonry Walls* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S5, “Masonry Walls.”

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedure(s) will be revised to include, into the scope of the program, masonry walls in the Auxiliary Service Building and Water Treatment Building.

Parameters Monitored / Inspected (Element 3), Monitoring and Trending (Element 5)

2. Procedure(s) will be revised to require inspection for 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.

Detection of Aging Effects (Element 4)

3. Procedure(s) will be revised to specify that the interval between inspections does not exceed five years.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Masonry Walls* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. While performing fire barrier inspections in 2018 in the Turbine Building, a crack was found in a masonry block that is part of the south wall. Fire protection compensatory actions were taken as required. A grout repair of the cracked masonry block was performed to correct the condition.
2. In 2018, the inspection of the east exterior wall of the Turbine Building, which is a fire barrier, revealed two ½ inch diameter holes in the wall. The holes did not completely penetrate the wall. Fire protection compensatory actions were taken as required. Engineering evaluated the condition, and a grout repair was performed to fill the holes.

3. In 2018, as one part of the engineering changes for external flood barrier modifications, a short, reinforced masonry wall, about 32 inches high, was added to keep storm run-off out of the RWST pit. The masonry wall is designed to withstand the effects of the design basis earthquake with appropriate reinforcing steel added. In 2019, the structures monitoring procedure was updated to include this new masonry wall into the scope of the masonry wall inspections.
4. In December of 2020, the documentation of the 5-year structures monitoring inspections was completed. The report for the 2020 structures monitoring inspections addresses the results of masonry wall inspections performed during August and September of 2020, which were included as part of the overall structures monitoring inspections. Some old cracking along mortar joints was identified in a few locations. In addition, as is typical with uninsulated masonry block structures, some ongoing peeling/flaking of the coatings at both the inside and outside wall surfaces was identified. The report concluded that the masonry walls were in acceptable condition and fully capable of performing their design functions. The results of masonry wall inspections included the following:
   - Small cracks in the Substation Relay House are being monitored and compared to previous inspections, with no changes identified.
   - Vertical cracks in mortar joints at several locations of exterior walls of the Fire Service Pumphouse were identified in 2020 and determined to be acceptable.
   - Cracking was identified as minor in the mortar around blocks in the east concrete masonry wall of the Turbine Building lube oil room. The crack was found to be unchanged from the last inspection and was determined to not be a structural concern.
   - As part of the inspections for exterior structures outside of the Auxiliary Building, the block wall constructed in 2019, to support exterior flood protection at the RWST tank, which was mentioned in the previous OE, was inspected with no deficiencies noted.

The above examples of operating experience provide objective evidence that the *Masonry Walls* program includes activities to perform visual inspections to manage cracking, loss of material, and loss of material (spalling and scaling) for masonry walls within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Masonry Walls* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Masonry Walls* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Masonry Walls* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.35 Structures Monitoring

Program Description

The *Structures Monitoring* program is an existing condition monitoring program that manages aging of the structures and components that are within the scope of subsequent license renewal by managing the following aging effects:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; and loss of material (spalling, scaling)
- Cracking; loss of material
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material
- Loss of material; cracking
- Loss of material (spalling, scaling) and cracking
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking
- Reduction or loss of isolation function

The *Structures Monitoring* program implements the requirements of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” consistent with guidance of NRC Regulatory Guide (RG) 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” and Nuclear Management and Resources Council 93-01, “Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”

The *Structures Monitoring* program relies on periodic visual inspections to monitor and maintain the condition of structures and structural components. Inspections are conducted by qualified personnel at a frequency not to exceed five years. The interval between successive recurring inspections may be decreased based on conditions discovered in previous inspections. Evaluation of inspection results includes consideration 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. Inaccessible areas are assessed for aging and opportunistically inspected when made accessible by other plant activities.

For concrete and associated components, ACI-349.3R, “Evaluation of Existing Nuclear Safety-Related Concrete Structures,” and other applicable industry documents are used as guidance for the inspections, inspector qualifications, and evaluation of inspection results. The inspection program for structural steel is similar to the concrete program and will be based on the guidance provided by the American Institute of Steel Construction (AISC) Specification for Structural Steel Buildings and Code of Standard Practice. For earthen structures, evaluation of inspection results is performed by a qualified civil/structural engineer.

Procedures include preventive actions to ensure structural bolting integrity for replacement and maintenance activities by specifying 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. For structural bolting consisting of ASTM A325 and ASTM A490 bolts, preventive actions for lubricant selection, and bolting and coating material selection are consistent with Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts.” The storage of ASTM A325 and ASTM A490 bolts will be consistent with Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts.” Twist-off type ASTM F1852 and ASTM F2280 bolts are not specified or stocked for use.

In order to evaluate the potential of water to cause degradation of concrete, samples of groundwater are taken at intervals not to exceed five years. The water chemistry is evaluated and should the results of water testing indicate potentially harmful levels of substances such as chlorides > 500 ppm, sulfates > 1,500 ppm, or a pH < 5.5, excavation and examination of buried concrete surfaces may be necessary. Groundwater monitoring has shown the groundwater to be non-aggressive and there have been no indications of concrete degradation due to aggressive groundwater. Seasonal variations will be accounted for in the sampling of groundwater.

For surfaces provided with protective coatings, observation of the condition of the coating is an effective method for identifying the absence of degradation of the underlying material. Therefore, coatings on structures within the scope of the *Structures Monitoring* program are inspected only as an indication of the condition of the underlying material.

There has been no documented loss of material due to pitting or crevice corrosion or cracking of stainless steel or aluminum structural components within the scope of the *Structures Monitoring* program. The potential for loss of material or cracking of stainless steel and aluminum structural components exposed to air or condensation environments will be managed by the *Structures Monitoring* program.

Aluminum and stainless steel structural components such as louvers, cable trays, conduits, and structural supports will be monitored for loss of material and cracking due to SCC that could lead to the reduction or loss of their intended function.

Concrete inspectors are trained to identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program (B2.1.31), the *Structures Monitoring* program (B2.1.35), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.36).

Elastomeric vibration isolation elements are monitored for hardening by visual evidence of cracking and confirmed by tactile inspection.

Structural sealants, seismic gap joint filler, and other elastomeric materials will be monitored for cracking, loss of material, and hardening. These elastomeric elements are acceptable if the observed loss of material, cracking, and hardening will not result in a loss of intended function. Visual inspection of elastomeric elements will be supplemented by tactile inspection to detect hardening if the intended function is suspect.

The Spent Fuel Pool level is monitored by two level measurement loops that provide control room indication. High and low pool levels are annunciated in the Control Room and locally (FSAR, Section 9.1.3.5.3). Leakage from the Spent Fuel Pool telltale drains is evaluated by a separate procedure.

The *Masonry Walls* program (B2.1.34) is implemented as part of this program.

NUREG-2191 Consistency

The *Structures Monitoring* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S6, “Structures Monitoring.”

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedure(s) will be revised to include inspection of the following structures within the scope of subsequent license renewal: Auxiliary Service Building; alternate seal injection diesel generator (XEG0101) and control panel (XPN5587) (foundations and anchors); carbon dioxide tank (foundation and anchors); Circulating Water Intake Structure (includes Fire Service Pumphouse); the concrete pad supporting piping and equipment for filling Emergency Diesel Generator fuel oil tanks; 115 kV yard equipment (supports, foundations and anchors) from the plant including transformer XTF-4 and voltage regulator, XTF-6 and electrical switch XES-8, through and including electrical circuit switcher XES-4; electrical manholes EMH(s) 9, 11, 31,

32, 46, 47, 70, 72, 74, 75, and 76; sodium hydroxide tank (foundation and anchors); Unit 1 Relay House; and the Water Treatment Building. Baseline inspections for the added structures will be performed under the enhanced program to establish quantitative inspection data prior to conduct of periodic inspections in the subsequent period of extended operation.

Scope of Program (Element 1) and Parameters Monitored / Inspected (Element 3)

2. Procedure(s) will be revised to include inspection of the following structural components: battery racks, cable bus enclosures and tap box enclosures (external surfaces and supports and support foundations), cable trays and conduits, cable trenches and covers (between Unit 1 Relay House, the Substation Relay House, and the 230 kV breaker XCB-8892), 230 kV substation lightning arrestor poles and foundations, doors, elastomeric materials, electrical duct banks, louvers, masonry wall edge support and bracing members, panels and other enclosures, penetration seals, pipe whip restraints and jet impingement shields (includes guard pipes used as shields against spray or jet impingement), sump and pool liners, switchyard bus supports, transmission towers, racks, trash racks (for Circulating Water Intake Structure), and tube tracks.

Preventive Actions (Element 2)

3. Procedure(s) will be revised to require storage of ASTM A325 and ASTM A490 bolts and associated nuts and washers be in closed containers to protect them from dirt and corrosion and the closed containers be stored in a protected shelter (Storage Level B or C) until use.

Parameters Monitored / Inspected (Element 3)

4. Procedure(s) will be revised to require inspection of structural steel bracing and edge supports associated with masonry walls for deflection or distortion, loose bolts, and loss of material due to corrosion.

Parameters Monitored / Inspected (Element 3) and Detection of Aging Effects (Element 4)

5. Procedure(s) will be revised to require inspection of elastomeric materials including structural sealants for cracking, loss of material, and hardening include the use of tactile inspection to detect hardening if the intended function is suspect.
6. Procedure(s) will be revised to require, where leakage volumes allow, monitoring and trending of through wall leakage or water infiltration and leaching deposits for volume and chemistry (for pH, mineral, calcium, chloride, sulfate and iron content) to evaluate any potential effect on the concrete or reinforcing steel.

Parameters Monitored / Inspected (Element 3) and Acceptance Criteria (Element 6)

7. Procedure(s) will be revised to require monitoring of aluminum and stainless steel structural components such as louvers, cable trays, conduits, and structural supports for loss of material and cracking due to SCC that could lead to the reduction or loss of their intended function.

Detection of Aging Effects (Element 4)

8. Procedure(s) will be revised to require accounting for seasonal variations in the sampling of groundwater (e.g., quarterly monitoring every 5th year).
9. Procedure(s) will be revised to indicate excavation and focused examination of a sample of below grade concrete exposed to groundwater, or other measures, may be necessary every five years to detect potential concrete degradation if the groundwater in contact with the structures is determined to be aggressive.
10. Procedure(s) will be revised to require indications of groundwater infiltration or through-concrete leakage require assessment for aging effects which may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels.

Acceptance Criteria (Element 6)

11. Procedure(s) will be revised to incorporate the ACI 349.3R Chapter 5 ‘second-tier' evaluation criteria as quantitative acceptance criteria for concrete surfaces.
12. Procedure(s) will be revised to require evaluation criteria for steel structures be based on the judgment of a qualified structural engineer using the AISC Specification for Structural Steel Buildings and Code of Standard Practice.
13. Procedure(s) will be revised to specify:
    a. Loose nuts and bolts are not acceptable (unless accepted by engineering evaluation).
    b. Structural sealants are acceptable if observed loss of material, cracking, and hardening will not result in loss of sealing.
    c. Sliding surfaces are acceptable if (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.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Structures Monitoring* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2011, the 5-year Structures Monitoring inspections were completed. Groundwater intrusion into structures was noted as eliminated or greatly reduced. Groundwater chemical analysis sampling results indicated that the groundwater remained non-aggressive. The inspection results noted minor instances of degradation such as concrete cracks, ground water intrusion, leaching, structural steel rusting, paint flaking, and roofs leaking. The inspection results and

the overall condition for each structure were evaluated by Engineering and determined to be acceptable, with no structural significance. In most cases, the conditions identified were existing. When compared with the previous inspection report in 2005, no significant changes were noted. As documented in the inspection report, the structures inspected were free of deficiencies that could potentially lead to failure to perform their required structural design functions prior to the next scheduled inspection.

2. In 2016, the 5-year Structures Monitoring inspections were completed. Groundwater chemical analysis sampling results indicated that the groundwater remained non-aggressive. Sample results from one well, noted as going dry, indicated a pH reading slightly below the 5.5 pH threshold at which water is considered aggressive to concrete. This pH reading was significantly different than the other wells sampled. Chemical analysis results of a sample from a nearby dewatering well were obtained and the pH for that sample was 7.45. Engineering determined the low pH indication was an out-lier, and not representative of groundwater in contact with structures. Seismic gaps were inspected at various locations and were found as detailed on plant drawings with no degradation noted. Minor instances of degradation were noted in the inspection report such as concrete cracks, ground water intrusion, leaching, structural steel rusting, paint flaking, and roofs leaking. The inspection results and the overall condition of the structures were evaluated and determined to be acceptable, with no structural significance. In most cases, the conditions had already existed. When compared with the previous inspection report in 2011, no significant changes were noted. Engineering determined that the structures inspected were free of deficiencies that could potentially lead to failure to perform their required structural design functions prior to the next scheduled inspection.

3. In 2019, during Structures Monitoring inspections, corrosion was noted on an Auxiliary Building roof beam, a girder, and some adjacent roof decking. Based on an engineering evaluation, it was determined that the metal loss was minor and had no impact on structural function. The decking, beam and girder were recoated to prevent further occurrences.

4. In 2020, the 5-year Structures Monitoring inspections were completed. Groundwater chemical analysis sampling results indicated the groundwater remained non-aggressive. The inspection results noted minor instances of degradation, such as concrete cracks, ground water intrusion, leaching, structural steel rusting, paint flaking, roofs leaking. The noted observations and the overall condition of the structures were evaluated, accepted, with no structural significance. In many cases, the conditions identified had already existed. When compared with the previous inspection report in 2015, no significant changes were noted. Engineering concluded that the structures inspected were free of deficiencies that could potentially lead to failure to perform their required structural design functions prior to the next scheduled inspection.

The above examples of operating experience provide objective evidence that the *Structures Monitoring* program includes activities to perform periodic visual inspection and monitoring of the condition of concrete and steel structures, structural components, component supports, and structural commodities to identify aging effects for structures, structural supports, and structural commodities within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Structures Monitoring* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Structures Monitoring* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Structures Monitoring* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.36 Inspection of Water-Control Structures Associated with Nuclear Power Plants

Program Description

The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program is an existing condition monitoring program, which manages the following aging effects:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of material; loss of form
- Loss of preload

The program consists of inspection and surveillance of raw water-control structures associated with emergency cooling systems or flood protection, which are the North Berm, Service Water Discharge Structure, Service Water Intake Structure, Service Water Pond (earthen dams and earthen embankments), and Service Water Pumphouse. Inspection and surveillance of the water-control structures is in accordance with NRC Regulatory Guide (RG) 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants.” The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program performs periodic visual inspections at a frequency not to exceed five years to monitor and maintain the condition of water-control structures within the scope of subsequent license renewal. The program will include steel elements and structural bolting associated with water-control structures.

Qualifications for personnel performing concrete inspections and evaluations will be consistent with ACI 349.3R, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.” Inspections are performed and inspection results evaluated consistent with applicable industry documents to ensure that a loss of intended function does not occur.

In order to evaluate the potential of groundwater and Service Water Pond water to cause degradation of concrete, water samples are taken at intervals not to exceed five years under the *Structures Monitoring* program (B2.1.35). The water chemistry results are evaluated, and should the results of water testing indicate potentially aggressive levels of substances, such as chlorides > 500 ppm, sulfates > 1,500 ppm, or a pH < 5.5, then areas exposed to the water are assessed for aging.

Evaluation of inspection results will include consideration 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. Whenever inaccessible areas are excavated, exposed, or modified an opportunistic inspection will be performed.

Procedures include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension. For structural bolting consisting of ASTM A325 and ASTM A490 bolts, the preventive actions for lubricant selection, and bolting and coating material selection are consistent with Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts”. The storage of ASTM A325 and ASTM A490 bolts will be consistent with Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts”. Twist-off type ASTM F1852 and ASTM F2280 bolts are not specified or stocked for use.

Concrete inspectors are trained to identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program (B2.1.31), the *Structures Monitoring* program (B2.1.35), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program.

NUREG-2191 Consistency

The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S7, “Inspection Of Water-Control Structures Associated With Nuclear Power Plants.”

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedure(s) will be revised to include inspection of steel elements including miscellaneous steel, and structural bolting associated with water control structures.

Preventive Actions (Element 2)

2. Procedure(s) will be revised to require ASTM A325 and ASTM A490 bolts and associated nuts and washers to be stored in closed containers to protect them from dirt and corrosion. Additionally, the closed containers will be required to be stored in a protected shelter (Storage Level B or C) until use.

Parameters Monitored / Inspected (Element 3)

3. Procedure(s) will be revised to specify the parameters to be monitored and inspected for concrete structures include those described in ACI-201.1R and ACI-349.3R and include monitoring conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage.
4. Procedure(s) will be revised to specify steel components and bolting are inspected for loss of material due to corrosion, loose bolts, missing or loose nuts, other conditions indicative of loss of bolt preload, and cracked concrete around anchor bolts.
5. Procedure(s) will be revised to specify earthen structures are inspected for depressions, sinkholes, slope stability, and animal burrows.
6. Procedure(s) will be revised to require periodic determination and assessment of the bottom elevations of the Service Water Pond to ensure required water volume is maintained.

Detection of Aging Effects (Element 4)

7. Procedure(s) will be revised to require qualifications of inspection and evaluation personnel are consistent with ACI 349.3R for reinforced concrete water-control structures.
8. Procedure(s) will be revised to specify special inspections immediately following the occurrence of significant natural phenomena, such as large floods, hurricanes, tornadoes, or intense local rainfalls.
9. Procedure(s) will be revised to require indications of groundwater infiltration or through-concrete leakage be assessed for aging effects. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water.
10. Procedure(s) will be revised to require the underwater portions of the Service Water Pumphouse be included in the underwater structural inspections using a diver or dewatering, performed on a frequency not to exceed five years.
11. Procedure(s) will be revised to require the potential for aging affects for inaccessible, below-grade concrete structural elements be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.
12. Procedure(s) will be revised to specify examination of representative samples of the exposed portions of the below-grade concrete when excavated for any reason.

Monitoring and Trending (Element 5)

13. Procedure(s) will be revised to specify quantitative measurements and qualitative information be recorded and trended for findings exceeding the acceptance criteria for the applicable parameters monitored or inspected.

Acceptance Criteria (Element 6)

14. Procedure(s) will be revised to incorporate the ACI 349.3R Chapter 5 ‘second-tier' evaluation criteria as quantitative acceptance criteria for concrete surfaces.
15. Procedure(s) will be revised to specify engineering evaluations are documented and based on codes, specifications and standards such as AISC Specifications and those referenced in the plant's current licensing basis.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In November 2011, NRC Information Notice 11-20 (IN 11-20), “Concrete Degradation by Alkali-Silica Reaction,” was issued to notify licensees of the occurrence of alkali-silica reaction (ASR) induced concrete degradation of a Category 1 structure and indicated the unique 'map' or 'patterned' cracking and the alkali-silica gel that can be present and visibly identified on concrete areas likely to experience ASR. Review of IN 2011-20 concurred that ASR degradation could be readily identified during visual inspections by the distinct cracking patterns as well as the presence of alkali-silica gel. The review also indicated that photos of this distinctive cracking were included in ACI 201.1R which was referred to as applicable in the Maintenance Rule Structures Monitoring inspection procedures. Review of the Maintenance Rule Structures Monitoring inspection results did not identify any distinctive cracking indicative of ASR. Additionally, the results of ground water chemistry did not support aggressive attack and degradation due to ASR. No visual indications of ASR induced concrete degradation have been observed during subsequent regularly scheduled inspections of concrete structures.
2. In 2013, soil erosion in the natural land area located between the south and east dams was evaluated by Engineering and a plan to rework the areas was established. Three earthen dams, the south dam, east dam, and north dam together with the adjacent natural land areas and the earthen west embankment form the Service Water Pond. The Service Water Pond is located at the edge of and contained within the larger Monticello Reservoir and serves as a separate cooling water volume. The amount and location of eroded material in the natural land area located between the south and east dams was limited and determined to be insignificant

with no impact on the volume or function of the Service Water Pond, and the erosion had no impact on the capability of the south and east dams and the natural land area to perform their design function. The eroded areas were reworked in accordance with engineering direction. Subsequent inspections have not found similar erosion.

3. In 2013, as a result of industry benchmarking, Engineering initiated a bathymetric study on the Service Water Pond bottom elevations in order to verify that the water volume required for the ultimate heat sink function was available. The previous bathymetric study on the Service Water Pond had been performed in 1997. The bathymetric study performed (in 2013) recorded that the Service Water Pond volume was essentially unchanged and was determined to be acceptable.
4. In 2015, during a periodic visual inspection of the Service Water Pumphouse, light surface corrosion was noted on anchor bolts for a pump. A work order was initiated and the anchor bolts were subsequently cleaned and a protective coating was applied.
5. In 2018, the Service Water Intake Structure 5-year inspection was performed to detect new cracks in the structure, as well as changes to existing cracks. Inspections of the Service Water Intake Structure have been performed on a 5-year frequency since 1983. Comparison of identified surface cracking from previous inspection results confirmed that observed changes in individual cracks and patterns were minimal, and indicated there was no significant ongoing structure settlement.

The above examples of operating experience provide objective evidence that the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program includes activities to perform visual inspections to identify aging effects for water-control structures within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.37 Protective Coating Monitoring and Maintenance

Program Description

The *Protective Coating Monitoring and Maintenance* program is an existing condition monitoring program that manages loss of coating integrity of Service Level I coatings inside the Reactor Building. The program maintains and monitors the aging of Service Level I coatings consistent with NRC Regulatory Guide (RG) 1.54, Revision 3, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.”

Maintenance of Service Level I coatings is consistent with ASTM D 5163-08, “Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants.” The program includes activities to monitor and assess the material condition of Service Level I coatings applied to steel and concrete surfaces inside the Reactor Building by performing visual inspections with qualified inspectors to ensure there is no coating degradation. A pre-inspection review of previous containment coating condition assessment reports is performed prior to each refueling outage.

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside the Reactor Building (e.g., steel liner, structural steel, supports, penetrations, and concrete walls and floors) serves to prevent or minimize the loss of material of carbon steel components due to corrosion and aids in decontamination. This program ensures that the Service Level I coatings maintain adhesion so as to not affect the intended function of the emergency core cooling systems (ECCS) suction strainers.

The program also provides controls over the quantity of unqualified coatings. Unqualified coating may fail in a way that affects the intended function of the ECCS suction strainers. Therefore, the quantity of degraded and unqualified coating is controlled and assessed periodically to ensure that the amount of unqualified coating in the Reactor Building is kept within acceptable design limits of permitted degraded coatings to support the post-accident operability of the ECCS.

NUREG-2191 Consistency

The *Protective Coating Monitoring and Maintenance* program is an existing program that is consistent with NUREG-2191, Section XI.S8, “Protective Coating Monitoring and Maintenance,” as modified by SLR-ISG-2021-03-STRUCTURES, "Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance.".

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Protective Coating Monitoring and Maintenance* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2012, during a coatings walkdown in the Reactor Building outside the bio-wall, delaminated coatings were identified in three areas on the south stairwell handrail. Engineering determined that the areas of degraded coating on the south stairwell handrail were localized and not an indication of a large-scale condition with the coating. The degraded coating was repaired utilizing the procedure for the application and inspection of Service Level I protective coatings inside the Reactor Building. Coating repairs were performed In November 2012.
2. In October 2012, during a coatings walkdown of the steam generator 'A' loop in the Reactor Building, corrosion was identified at the 412 elevation on the steam generator hot leg support baseplate. Degraded coating was in an area that had been holding approximately one inch of water. Engineering determined that the area of degraded coating was localized and not an indication of a large-scale condition with the coating. The degraded coating was repaired utilizing the procedure for the application and inspection of Service Level I protective coatings inside the Reactor Building. Coating repairs were performed in November 2012.
3. In May 2014, during a Reactor Building coatings walkdown, Quality Control identified delaminated coatings and corrosion on a pipe extending from the control rod drive mechanism cooling water inlet penetration and cracking and flaking on a pipe extending from the main steam loop 'C' penetration. Engineering determined that the areas of degraded coatings were localized and not an indication of a large-scale condition with the coatings. The degraded coatings were repaired utilizing the procedure for the application and inspection of Service Level I protective coatings inside the Reactor Building. Coating repairs were performed In November 2015.
4. In October 2018, during a walkdown of the emergency feedwater piping in the Reactor Building, minor surface rust on the 'A' and 'C' loop piping was identified. The rust was due to condensation from overhead cold-water piping systems. No pitting corrosion, loss of material, or significant degradation was observed. The degraded coating was repaired utilizing the procedure for the application and inspection of Service Level I protective coatings inside the Reactor Building. Coating repairs were performed in April 2020.
5. During the Spring 2020 refueling outage, the Containment Inservice Inspection- ASME Section XI, Subsections IWE and IWL Responsible Engineer Evaluation Report identified loose coatings defects on IWE components such as the Containment liner, sump penetrations, and the RHR and Reactor Building spray guard pipes.

There were no findings that indicated actual, or potential, component degradation within the scope of the inspection. IWE components with degraded coatings, along with a conservative estimate of loose coatings, have been added to the list of unqualified coatings in the Reactor Building. The margin for unqualified coatings inside the Reactor Building is tracked with a calculation to ensure that the quantity of degraded and unqualified coatings is within the allowable design margin. Coating repair for these items was scheduled for a future refueling outage. Deferral of these coating repairs was based on assessments performed relative to post-LOCA debris load used in calculations for sump operability. Final disposition or repair of the identified conditions is tracked through the corrective action system.

The above examples of operating experience provide objective evidence that the *Protective Coating Monitoring and Maintenance* program includes activities to perform visual inspections to manage loss of coating integrity for Service Level 1 coatings within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Protective Coating Monitoring and Maintenance* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Protective Coating Monitoring and Maintenance* program will effectively identify aging prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The continued implementation of the *Protective Coating Monitoring and Maintenance* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.38 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages reduced electrical insulation resistance of accessible electrical cable and connection insulation material subject to an adverse localized environment.

An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the electrical cables (power, control, and instrumentation) and connections. The environment may be caused by temperature, radiation, or moisture. An adverse localized environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

The program performs a plant walkdown of in-scope structures to visually inspect for accessible cables and connections located in an adverse localized environment. Should an adverse localized environment be observed, accessible electrical cables and connections installed within that environment are visually inspected for the aging mechanisms associated with jacket surface and connection covering anomalies, such as embrittlement, discoloration, cracking, melting, swelling or surface contamination. These anomalies may indicate signs of reduced electrical insulation resistance.

A review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation will be performed.

The accessible electrical cable jacket and connection covering materials are to be free from unacceptable visual indications of surface anomalies which suggest that conductor insulation or connection covering degradation exists.

Visual inspection results that do not conclude that the cable and connection insulation material is free from unacceptable indications due to surface anomalies are evaluated in the Corrective Action Program.

Additionally, visual inspection findings may necessitate testing. Should testing be deemed necessary based on unacceptable visual indications of surface anomalies, a sample size of 20% of each cable and connection insulation material type found within the adverse localized environment with a maximum sample size of 25 will be tested. The following factors will be considered in the development of the cable and connection insulation test sample: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location (high temperature, high humidity, vibration, etc.), and insulation material. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. The technical basis for the sample selected is provided. The electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in the procedures.

The visual inspection frequency is based on engineering evaluation and will be performed prior to the period of extended operation and at least once every ten years.

NUREG-2191 Consistency

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.E1, "Electrical Insulation For Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Parameters Monitored / Inspected (Element 3)

1. Procedure(s) will be revised to add the requirement to identify adverse localized environments through plant operational experience reviews, communication with maintenance, operations, and radiation protection personnel, and the use of environmental surveys for determining each of the most limiting cable and connection electrical insulation plant environments (e.g.: caused by temperature, radiation, moisture, or contamination.)
2. Procedure(s) will be revised to include a list of structures/areas to perform/conduct the visual inspections of cables and connections.

Parameters Monitored / Inspected (Element 3) and Detection of Aging Effects (Element 4)

3. Procedure(s) will be revised to add the requirement to perform a review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation.

Detection of Aging Effects (Element 4)

4. Procedure(s) will be revised to add a description of testing methodology: Should testing be deemed necessary based on unacceptable visual indications of surface anomalies, a sample size of 20% of each cable and connection insulation material type found within the adverse localized environment with a maximum sample size of 25 will be tested. The following factors will be considered in the development of the cable and connection insulation test sample: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location (high temperature, high humidity, vibration, etc.), and insulation material. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. The technical basis for the sample selected is provided.
5. Procedure(s) will be revised to specify the visual inspection be performed prior to the period of extended operation and at least once every 10 years thereafter.

Acceptance Criteria (Element 6)

6. Procedure(s) will be revised to require the test results for electrical cable and connection insulation material be verified to confirm they are within the acceptance criteria identified in the procedure(s).

Corrective Actions (Element 7)

7. Procedure(s) will be revised to add the requirement to include the performance of an Engineering evaluation of unacceptable test results and visual indications of cable and connection electrical insulation abnormalities. The evaluation will consider 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).

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In November 2012, I&C maintenance personnel discovered field cable insulation that had heat damage while performing work on a pressurizer vapor temperature element. A condition report was written to document the condition and initiate corrective actions. The field cable insulation was determined to be functional; however, the heat had caused it to become brittle near the ring lugs, so the damaged insulation needed repair or replacement. The cable was de-terminated at the termination box, new cable was re-pulled, and cable splice was installed in the termination box. The damaged portion of the circuit cable was replaced with the original cable type.
2. In November 2012, an evaluation of an industry operating experience event was performed to identify gaps in procedures and preventive maintenance activities. This event described an automatic reactor scram from 100% power on a reactor coolant pump trip as a result of medium-voltage cable insulation failure. As a result of the evaluation, new procedures and associated recurring events for periodic maintenance were created to visually inspect the reactor coolant pump motor terminations and associated cabling/insulation at each motor swap occurrence. The reactor coolant pump motors are swapped every nine years. These actions were based on the low risk of cable degradation in the installed environment for these cable types. Since the implementation of the new procedures and maintenance activities there have been two reactor coolant pump motors swapped (one in the Spring of 2017, and one in the Fall of 2018) with no cable insulation damage identified.
3. In May 2017, during the performance of a maintenance activity, a conductor with a corona glow was identified in a bus duct (cable bus). White corona dust was also observed on another conductor in the cable bus. A condition report was submitted to document the condition and corrective actions were initiated. The entire cable bus was fully inspected and additional areas with evidence of corona damage were found. Laboratory testing, conducted on thirty-six cable samples, confirmed and the observed condition was superficial cable jacket damage that had no impact on the cable insulation. Corona discharge can occur due to ionization of air in the gap where phase-to-phase contact is present and is indicated by a white powder in the vicinity of the discharge. Accordingly, the observed conditions were concluded to be a result of corona discharge that had occurred when of two unshielded energized cable bus cables were in contact with each other. The unshielded cable bus cables were replaced with shielded cables to preclude recurrence. The remaining cable bus circuits were inspected and no further evidence of corona damage was observed.
4. In October 2018, a report was completed documenting the initial license renewal inspections. The Reactor Building inspections were conducted during the April 2017 refueling outage. Inspections for the other buildings were conducted in 2018 between July and August. The inspection results for non-EQ cables and fuse blocks were documented in inspection reports for the Auxiliary Building, Intermediate Building, Turbine Building, Diesel Building and Reactor Building non-EQ cable walkdown observations.

The walkdowns included visual inspections of cable jacket or connection surfaces to detect abnormalities such as embrittlement, cracking, swelling, discoloration, surface contamination, presence of standing water or moisture, or any other visible evidence of age-related degradation, which may lead to loss of the intended function. As documented in the inspection reports, there were no noted cable conditions that if left unmanaged, could lead to a loss of intended function of the related equipment in the buildings and locations within the scope of the report. Since no visual cable concerns were noted, there were no preventive actions or additional corrective actions required as a result of the inspections. In addition to the visual inspections, thermographic scans were performed to detect potential heating issues with no areas of concern identified.

The above examples of operating experience provide objective evidence that the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program includes activities to perform visual inspections to identify reduced electrical resistance for accessible electrical cables and connections insulation material subjected to an adverse localized environment within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.39 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

Program Description

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program is an existing performance monitoring program that manages reduced electrical insulation resistance of the electrical cables and connections (cable system) insulation material used in instrumentation circuits with sensitive, high-voltage, low-level current signals that are subjected to adverse localized environments caused by temperature, radiation, or moisture.

Exposure of electrical cables to adverse localized environments can result in reduced insulation resistance. Reduced insulation resistance causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in insulation resistance is a concern for circuits with sensitive, high voltage, low-level current signals because a reduced insulation resistance may contribute to signal inaccuracies.

The program applies to non-EQ cables and connections for the Containment high range area radiation monitors, steam line high range gamma monitors, atmospheric radiation monitors, and neutron flux monitoring instrumentation that are sensitive to a reduction in conductor electrical insulation resistance.

The Containment high range area radiation monitor cables, and the atmospheric radiation monitors cables are connected during calibration. The results of normal calibration or surveillance testing are reviewed to detect electrical cable and connection insulation material aging degradation. The first reviews are completed prior to the subsequent period of extended operation and at least once every 10 years thereafter.

The steam line high range gamma monitors, and the neutron flux monitoring instrumentation cables are disconnected during calibration. A proven cable test for detecting deterioration of the cable system insulation is performed. The test frequency is determined by engineering evaluation, but at least once every 10 years. The first tests are completed prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program is an existing program that is consistent with NUREG-2191, Section XI.E2, “Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In July 2022, an OE search from January 2011 was performed for plant-specific OE related to cable and connection insulation for non-EQ sensitive instrumentation circuits. Although cases of defective detectors were identified during testing and maintenance activities, no examples of reduced insulation resistance due to aging were identified for non-EQ sensitive instrumentation circuits.
2. In November 2018, a report was completed documenting the initial license renewal testing for non-EQ sensitive instrumentation circuits that were disconnected during calibration. The report documented the insulation resistance testing and results for the nuclear instrumentation power range detector circuits.

   Impedance, Insulation Resistance, IV Curve Comparisons, Time Domain Reflectometry, Reverse Time Domain Reflectometry, Frequency Domain Reflectometry, and Indenter Modulus test were performed. Results of the testing concluded there were no immediate problems or concerns that would affect normal detector operation and no age-related degradation or other cable circuit anomalies were identified.
3. In May 2020, a report was completed documenting the initial license renewal testing for the non-EQ sensitive instrumentation circuits that were disconnected during calibration. The report documented the insulation resistance testing and results for the nuclear instrumentation source and intermediate range, and steam line high range gamma monitors circuits.

   Impedance, Insulation Resistance, IV Curve Comparisons, Time Domain Reflectometry, Reverse Time Domain Reflectometry, Frequency Domain Reflectometry, and Indenter Modulus tests were performed. Results of the testing concluded there were no immediate problems or concerns that would affect normal detector operation and no age-related degradation or other cable circuit anomalies were identified.

The above examples of operating experience provide objective evidence that the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program includes activities to perform testing to identify reduced electrical insulation resistance for electrical cable and connection (cable system) electrical insulation material subject to sensitive, high-voltage, low-level current signals that are subjected to adverse localized environments caused by temperature, radiation, or moisture within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.40 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages reduced electrical insulation resistance or degraded dielectric strength of inaccessible or underground medium-voltage power cables (operating voltages of 2kV to 35 kV) within the scope of subsequent license renewal exposed to significant moisture.

The program applies to inaccessible or underground non-EQ medium-voltage power cable installations (e.g., installed in buried conduits, embedded raceway, duct banks, underground vaults, manholes, cable trenches or direct buried installations), within the scope of subsequent license renewal and potentially exposed to significant moisture. Inaccessible medium-voltage power cables designed for continuous wetting or submergence are also included in this program for a one-time inspection and test. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function. Power cable exposure to significant moisture may cause reduced electrical insulation resistance or degraded dielectric strength that can potentially lead to failure of the cable's insulation system. Cable wetting or submergence that results from event driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for this program.

Periodic actions are taken to prevent non-EQ inaccessible or underground medium-voltage power cables from being exposed to significant moisture, including cables specifically designed for continuous wetting or submergence. Accessible cable conduit endpoints and manholes associated with in-scope non-EQ inaccessible medium-voltage power cables included in this program (i.e., installed in duct banks and manholes) are inspected for water accumulation and the water is drained, as necessary. Manholes associated with in-scope non-EQ inaccessible medium-voltage power cables are inspected to confirm that cables are not wetted or submerged in water; cables, manholes and cable support structures are intact; and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. This inspection and any necessary water removal is performed based on actual plant-specific experience over time. The inspection frequency will be at least once a year. Inspections will be performed after event-driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding). Dewatering devices and associated alarms are inspected, and their operation verified periodically, as applicable. Inspections of manholes equipped with water level monitoring and alarms will also be performed following event-driven occurrences if water accumulation is indicated by the monitoring system (e.g., frequent level alarm), as applicable. Manholes associated with in-scope non-EQ inaccessible medium-voltage power cables are not equipped with automatic water level monitoring and alarm systems.

In-scope non-EQ inaccessible medium-voltage power cables routed through manholes and duct banks are tested to detect reduced electrical insulation resistance or degraded dielectric strength of the cable's insulation system. Testing that is appropriate to the application at the time of the testing is performed. Cable testing includes one or more proven testing methods (such as dielectric loss [dissipation factor (Tan-Delta)/power factor], AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, or line resonance analysis). Cable testing acceptance criteria are defined prior to each test. Cables are tested at least once every six years. More frequent testing may occur based on test results and operating experience.

A plant-specific inaccessible medium-voltage cable test matrix is used to document inspection methods, test methods, and acceptance criteria for the in-scope inaccessible medium-voltage power cables.

There are no submarine cables or other cables designed for continuous wetting or submergence currently in the scope of this program.

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is implemented as a Fleet program at Dominion Energy. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196), and determinations were made for each station that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.E3A, “Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” as modified by SLR-ISG-2021-04-ELECTRICAL, "Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance."

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. Procedure(s) will be revised to inspect and dewater, if required, the in-scope manholes after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.
2. Procedure(s) will be revised to clarify that the frequency of manhole inspections will occur at least once a year.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2011, an industry operating experience event was evaluated to identify gaps in procedures and preventive maintenance activities. The industry event described an automatic reactor scram from 100% power on loss of electrical load as a result of a ground fault on the feeder cable from the station power transformer. This industry event was evaluated during the development of the Electrical Cable Reliability Management Program (ECRMP). As a result of the evaluation, medium-voltage and low-voltage power and control cable subject to adverse service conditions (such as moist environments) were included in the ECRMP. The cables within the scope of the ECRMP program are monitored, trended, and tested for insulation degradation to ensure reliability.
2. In April 2013, the water level in an in-scope manhole exceeded the acceptance criteria in the manhole inspection procedure. Several cables were identified to be in contact with the water. The as-found condition was due to planned excavation, during implementation of a plant modification, that had caused temporary changes in the land grading. The rain and drain design of the manhole was determined to be working, but the short-term grading changes had caused it to be temporarily overwhelmed. A sump pump was made available until the excavation was complete and the grading was restored to an acceptable condition. No further issues with water in that manhole have been noted.
3. In July 2019, water was discovered in an electrical manhole due to a domestic water leak. No cables were submerged, and the water level was within the acceptance criteria of the manhole inspection procedure, so pumping was not required.

4. In February 2021, an engineering review and evaluation was performed for the cables and manholes in the scope of the Inaccessible Medium-Voltage Cables Not Subject to 10CFR50.49 Environmental Qualification Requirements program. A five-year review of historical manhole inspection work orders was performed. The review concluded the acceptance criteria for the manhole inspections was met. A review of the cable test data was performed, and the acceptance criteria was met for a good condition assessment of the cables, which allows a test frequency of at least once every six years.

The above examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program includes activities to perform testing of cable and visual inspections of manholes to identify reduced electrical insulation resistance or degraded dielectric strength for non-EQ inaccessible medium-voltage power cables (operating voltage of 2kV to 35kV) exposed to significant moisture within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.41 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage reduced electrical insulation resistance or degraded dielectric strength leading to electrical failure of in-scope non-EQ inaccessible and underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) instrument and control (I&C) cables exposed to significant moisture, including cables designed for continuous wetting or submergence. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence resulting from event driven occurrences and mitigated by either automatic or passive drains is not considered significant moisture.

Periodic actions will be taken to prevent inaccessible and underground I&C cables from being exposed to significant moisture. Manholes associated with in-scope non-EQ inaccessible and underground I&C cables will be inspected for water collection, and the water will be drained, as necessary. Inspections will confirm that cables are not wetted or submerged. The inspection and water removal will be performed based on actual plant-specific experience over time with inspection frequency being at least once per year and after event-driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding). The first inspection will occur before the subsequent period of extended operation. Additional inspections will be conducted if one of the inspections does not meet the acceptance criterion due to current or projected degradation (i.e., trending). The number of increased inspections will be determined in accordance with the Corrective Action Program. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.

In-scope, non-EQ, inaccessible and underground I&C cables exposed to significant moisture will be evaluated to determine if testing is required. If required, initial testing will be performed on a sample population to determine the condition of the electrical insulation. One or more tests may be required due to the cable type, application, and electrical insulation to determine degradation of the electrical insulation. A one-time test prior to the subsequent period of extended operation will be performed for cable exposed to significant moisture if the cable insulation type is known to degrade with continuous exposure to moisture or if operating experience indicates insulation degradation resulting from continuous exposure to moisture. Tests may include combinations of in-situ or laboratory, electrical, physical, or chemical tests. The need for additional periodic tests and inspections will be determined by the test results and/or inspection results, as well as industry and plant-specific operating experience.

Testing of installed in-service inaccessible and underground I&C cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage or low-voltage cable subject to the same or bounding service environment, in-service application, cable routing, construction, manufacturing and insulation material may be credited in lieu of, or in combination with, testing of installed in-service inaccessible I&C cables when testing is recommended. A sampling methodology will be used to evaluate a large number of I&C cables exposed to a significant moisture event.

NUREG-2191 Consistency

The *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," as modified by SLR-ISG-2021-04-ELECTRICAL, "Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance."

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following example of operating experience provides objective evidence that the *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In February 2021, Engineering performed an evaluation to document the extent of water accumulation in two manholes containing safety-related cables. Both manholes contained medium-voltage power cables and instrumentation and control cables. The evaluation included results from manhole inspections that had been performed monthly during the previous five years. Specifically, during the five years of inspections, no findings of water had been identified in manhole #1 and only occasional instances of water had been identified in manhole #2 (the depth not sufficient to contact the cables). Based on these findings, the inspection frequency for both manholes was revised from monthly to quarterly.

The above example of operating experience provides objective evidence that the *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will include visual inspections to identify cable insulation and jacket abnormalities, and insulation resistance testing if necessary to identify insulation degradation for I&C electrical cables within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will effectively manage aging prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.42 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage reduced electrical insulation resistance or degraded dielectric strength of non-EQ inaccessible and underground low-voltage (operating voltage less than 2kV) power cables within the scope of subsequent license renewal, and potentially exposed to significant moisture.

Periodic actions will be taken to prevent non-EQ inaccessible and underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried) low-voltage power cables from being exposed to significant moisture, including cables specifically designed for continuous wetting or submergence. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence resulting from event driven occurrences and mitigated by either automatic or passive drains is not considered significant moisture. Manholes/vaults associated with in-scope non-EQ inaccessible low-voltage power cables will be inspected to confirm cables are not wetted or submerged in water, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. The inspections and any necessary water removal will be performed based on actual plant-specific operating experience with wetting or submergence over time. The inspection frequency will be at least once per year and after event-driven occurrences such as heavy rain, rapid thawing of ice and snow, or flooding. The first inspection will occur before the subsequent period of extended operation. Supplemental inspections will be conducted if one of the inspections does not meet the acceptance criteria due to current or projected degradation (i.e., trending).

In-scope, non-EQ, inaccessible low-voltage power cables found to be exposed to significant moisture will be evaluated to determine if testing is required. If required, initial testing will be performed on a sample population to determine the condition of the electrical insulation. One or more tests may be required due to the cable type, application, and electrical insulation to determine the condition of the electrical insulation. A one-time test prior to the subsequent period of extended operation will be performed for cable exposed to significant moisture if the cable insulation type is known to degrade with continuous exposure to moisture or if operating experience indicates insulation degradation resulting from continuous exposure to moisture. Tests may include combinations of in situ or laboratory, electrical, physical, or chemical tests. The need for additional periodic tests and inspections will be determined by the test results and/or inspection results, as well as industry and plant-specific operating experience. Additional inspections will be conducted if one of the inspections does not meet the acceptance criteria due to current or projected degradation. The number of increased inspections will be determined in accordance with the Corrective Action Program.

Testing of installed in-service non-EQ inaccessible and underground low-voltage power cables as part of an existing maintenance, calibration or surveillance program; or testing of coupons, abandoned or removed cables, or inaccessible medium-voltage or instrument and control cable subject to the same or bounding service environment; or in-service application, cable routing, construction, manufacturing and insulation material may be credited in lieu of, or in combination with, testing of installed in-service non-EQ inaccessible low-voltage power cables when testing is recommended. A sampling methodology will be used for cable evaluations when a large number of non-EQ inaccessible low-voltage power cables is exposed to a significant moisture event.

NUREG-2191 Consistency

The *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.E3C, “Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” as modified by SLR-ISG-2021-04-ELECTRICAL, "Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance."

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following example of operating experience provides objective evidence that the *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In June 2022, a search for plant-specific OE related to low-voltage power cables since January 2011 was performed. A few instances were identified for which water had been present in manholes, but there were no documented examples of non-EQ, low-voltage power cables being subjected to significant moisture that could cause degradation of the cable insulation.

The above example of operating experience provides objective evidence that the *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will include visual inspections to identify reduced electrical insulation resistance or degraded dielectric strength for non-EQ inaccessible low-voltage power cables within the scope of subsequent license renewal due to the presence of significant moisture or submergence, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be evaluated to ensure there is no significant impact to the safe operation of the plant, and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will effectively manage aging prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.43 Fuse Holders

Program Description

The *Fuse Holders* program is a new condition monitoring program that will manage increased electrical resistance of connection of the metallic clamps and reduced electrical insulation resistance of the fuse holder electrical insulation material.

The *Fuse Holders* program will specifically address aging management of fuse holder insulation material and fuse holder metallic clamp aging mechanisms and effects. The *Fuse Holders* program will utilize 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 insulators and metallic clamps are managed.

Fuse holders located outside of active equipment, where fuses are removed and replaced frequently for maintenance or surveillance activities are also included within this program to manage these repetitive activities.

The metallic portion of fuse holders that are within the scope of subsequent license renewal and subject to aging management will be tested for the following aging stressors: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and insertion, or vibration. Thermography will be used to test the metallic portion of fuse holders for increased resistance of the connection.

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

The first visual inspections and testing will be performed prior to the subsequent period of extended operation and at least once every 10 years thereafter.

NUREG-2191 Consistency

The *Fuse Holders* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.E5, “Fuse Holders.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following example of operating experience provides objective evidence that the *Fuse Holders* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2022, a search for plant-specific operating experience for fuse holders related to loose fuse holders from January 2011 was performed. A few occurrences were identified where loosening of fuses in fuse holders had been noted during testing and maintenance activities. There were no documented examples of fuse holders outside of active devices which had increased resistance of connection due to the aging mechanisms of chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement, or vibration.

The above example of operating experience provides objective evidence that the *Fuse Holders* program will include activities to perform testing and visual inspections to identify increased electrical resistance of connection of the metallic clamps and reduced electrical insulation resistance of the fuse holder electrical insulation material within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fuse Holders* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Fuse Holders* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Fuse Holders* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.44 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage increased electrical resistance of the electrical cable connections (metallic parts).

This program will perform a one-time test, on a representative sampling basis, to confirm the absence of loosening of connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion and oxidation. The following factors will be considered for sampling: voltage level (medium and low voltage), circuit loading (high load), connection type (crimped, bolted, and tap box), and location (high temperature, high humidity, vibration, etc.).

Non-EQ electrical cable connections (metallic parts) associated with cables within the scope of subsequent license renewal will be tested prior to the subsequent period of extended operation to provide an indication of the integrity of the cable connections. The specific type of test to be performed will be determined based on the type of connection and will be a proven method for detecting loose connections, such as thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation such as heat shrink tape, sleeving, insulating boots, etc.

A representative connector sample size consists of 20% of a connector type population with a maximum sample of 25. Otherwise a technical justification of the methodology and sample size used for selecting components under test will be included as part of the program's documentation.

A representative sample of cable connections within the scope of subsequent license renewal will be tested on a one-time test basis or at least once every five years if only visual inspection is used to provide an indication of the integrity of the cable connections. Depending on the findings of the one-time test, subsequent testing may have to be performed within ten years of initial testing. The first visual inspections or tests for subsequent license renewal will be completed prior to the subsequent period of extended operation. As an alternative to testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of insulation materials to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination may be implemented. When this alternative visual inspection is used to check cable connections, the first inspection will be completed prior to the subsequent period of extended operation and repeated at least once every five years, thereafter. The basis for performing only the alternative visual inspection to monitor age-related degradation of cable connections will be documented.

NUREG-2191 Consistency

The *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following example of operating experience provides objective evidence that the *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be effective in managing the aging effects for systems, structures, and components (SSCs) within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2022, a search for plant-specific OE related to loose connections from January 2011 was performed. Although cases of loosening of connections were identified during testing and maintenance activities, there were no conclusive examples that the loosening of connections was due to the aging mechanisms of thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation.

The above example of operating experience provides objective evidence that the *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will include activities to perform testing and visual inspections to identify increased electrical resistance for electrical cable connections (metallic parts) within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.45 High-Voltage Insulators

Program Description

The *High-Voltage Insulators* program is a new condition monitoring program that will manage loss of material and reduced electrical insulation resistance for insulators that are credited for recovery of offsite power. Insulators in the scope of this program operate at 115 kV and 230 kV and are of porcelain construction.

Insulator surfaces of porcelain insulators will be visually inspected to detect reduced electrical insulation resistance aging effects including cracks, missing sheds, foreign debris, excessive salt, dust, fog, cooling tower plume, and industrial effluent contamination. Metallic parts of the insulator will be visually inspected to detect loss of material due to mechanical wear and corrosion.

Insulators within the scope of the *High-Voltage Insulators* program will be visually inspected at least once every two years initially with the frequency adjusted based on plant-specific operating experience with the specific type of insulator. For insulators that are coated, the visual inspection will be performed at least once every five years.

The first inspection for the subsequent period of extended operation will be completed prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The *High-Voltage Insulators* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.E7, “High-Voltage Insulators,” as modified by SLR-ISG-2021-04-ELECTRICAL, "Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance."

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following example of operating experience provides objective evidence that the *High-Voltage Insulators* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In June 2011, during a walkdown of the Switchyard, an NRC Inspector noted several concerns including several insulators with chipped surfaces and one instance of a hold down bracket being partially welded to the bus line. Engineering surveyed the damage, determined the chips to be minor and the welded support structures able to continue to fulfill their design function. In October 2012, the insulators were repaired by applying a sealant to the porcelain insulators to seal the porcelain from moisture penetration. A review of results from subsequent inspections since August 2011 did not identify any other reported degradation of high voltage insulators.

The above example of operating experience provides objective evidence that the *High-Voltage Insulators* program will include activities to perform visual inspections to identify loss of material and reduced insulation resistance for high-voltage insulators within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *High-Voltage Insulators* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program will be informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *High-Voltage Insulators* program will effectively identify aging prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *High-Voltage Insulators* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B3 TLAA Support Activities

B3.1 Fatigue Monitoring

Program Description

The *Fatigue Monitoring* program is an existing program that manages cycle-based fatigue or other types of cyclic loading of the mechanical or structural components with a fatigue time-limited aging analysis (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. Parameters associated with operation of the pressurizer and pressurizer surge line during drawing and collapse of a bubble in the pressurizer (i.e., temperatures and pressures) are also monitored.

Examples of cycle-based fatigue analyses for which the *Fatigue Monitoring* program is used include, but are not limited to:

- Cumulative usage factor (CUF) analyses or their equivalent (e.g., I_c-based fatigue analyses, as defined in specific design codes) that are performed in accordance with American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) requirements for specific mechanical and structural components and piping,
- Implicit fatigue analyses, as defined by the ASME Code, Section III rules for Class 2 and Class 3 components or American National Standards Institute (ANSI) B31.1, 'Power Piping' design code,
- Fatigue analysis calculations for assessing the effects of the reactor water environment, known as environmentally-assisted fatigue (EAF) for sentinel locations in Class 1 equipment and piping,
- Fatigue flaw-growth analyses that are based on cyclic-loading assumptions,
- Fracture-mechanics analyses that are based on cyclic-loading assumptions,
- Fatigue waiver or exemption analyses that are based on cyclic-loading assumptions, and
- Class 1 piping analyses, which provided the basis for selecting high-energy-line-break (HELB) intermediate-piping break locations, where the CUF values must be maintained less than 0.1.

The program manages fatigue of components by monitoring one or more relevant fatigue parameters, which includes, but is not limited to the numbers of design transient cycles, the CUF values, the environmentally adjusted CUF (CUF_{en}) values, and the size of a flaw identified during an inservice inspection (for a fatigue crack-growth or flaw-tolerance evaluation that is credited for management of EAF). The limit of the fatigue parameter is established by the applicable fatigue analysis or flaw-tolerance analysis of the normal/alternate charging line cold leg nozzles, pressurizer surge line hot leg nozzle, and reactor vessel shell-to-outlet nozzle welds.

The program verifies the continued acceptability of analyses through cycle counting to ensure that the number of occurrences of each critical transient remains within the limits of the fatigue analyses, which in turn ensures that the analyses remain valid. Monitoring of design cycle transients is also used to ensure that the numbers of cyclic load occurrences assumed in fatigue crack-growth analyses and Class 1 fatigue waivers remain bounding. The program monitors and tracks the number of critical thermal and pressure transient occurrences applicable for these components and verifies that the severity of the monitored transients is bounded by the design transient limits of Technical Specification 5.7 and FSAR Table 5.2-2. Inservice inspection results are used, as required, to ensure that flaw sizes determined in a flaw-tolerance analysis are not exceeded.

The effects of reactor water environment on fatigue have been evaluated for the set of sample critical components from NUREG/CR–6260, 'Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components,' and additional components that are more limiting than those considered in NUREG/CR-6260. The environmental effects on fatigue for the critical and additional components were assessed using the positions described in Regulatory Guide (RG) 1.207, Revision 1, 'Guidelines for Evaluating the Effects of Light Water Reactor Coolant Environments in Fatigue Analyses of Metal Components,' and the methods described in NUREG/CR-6909, Revision 1, 'Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials.'

The *Fatigue Monitoring* program relies on the *Water Chemistry* program (B2.1.2) to provide monitoring of appropriate environmental parameters for calculating environmental fatigue multipliers (F_{en} values).

Fatigue waiver analyses meeting the criteria specified in the ASME Code, Section III, Subsection NB-3222.4(d), provide justification for not requiring a detailed fatigue calculation. Design analyses of ASME Code, Section III, Class 2 and 3 components include implicit fatigue evaluations specifying the allowable stress limits, based upon the number of anticipated full-temperature range transient cycles. The number of 80-year projected transients for the Class 2 and 3 components is bounded by the number of 40-year design transients.

In some cases, flaw-tolerance evaluations are used to establish inspection frequencies for components that are predicted to exceed CUF_{en} fatigue limits. ASME Code, Section XI, Nonmandatory Appendix L evaluations were developed for the normal/alternate charging line cold leg nozzles, and pressurizer surge line hot leg nozzle. Based upon the Appendix L flaw-tolerance evaluations, the effects of aging due to EAF for these locations is managed by application of the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1).

PWROG 17031-NP-A, Revision 1, includes a flaw-tolerance evaluation that was developed in accordance with ASME Section XI, Non-Mandatory Appendix A, which demonstrates that a postulated flaw in the reactor vessel shell-to-outlet nozzle weld will not grow to a critical flaw size through 80 years of plant operation. Based upon the results of the Appendix A flaw-tolerance evaluation, EAF of this location is managed by application of the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1).

The program monitors and tracks the number of occurrences of each of the critical thermal and pressure transients that are used in the Appendices A and L flaw-tolerance evaluations to verify the numbers of cycles do not exceed the numbers of analyzed cycles and to validate that the inspection frequencies remain appropriate.

NUREG-2191 Consistency

The *Fatigue Monitoring* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section X.M1, Fatigue Monitoring.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements:

Parameters Monitored (Element 3); Detection of Aging Effects (Element 4); Monitoring and Trending (Element 5); Acceptance Criteria (Element 6); and Corrective Actions (Element 7)

1. Procedure(s) will be revised to require:
    a. Transient cycles associated with the ASME Code, Section XI, Appendix A and L fatigue-sensitive locations be identified and tracked each ten-year interval.
    b. A surveillance limit be established for transient cycles associated with the ASME Code, Section XI, Appendix A and L fatigue-sensitive locations and corrective actions be initiated prior to exceeding the ASME Code, Section XI, Appendix A or L analyses transient cycle assumptions.

Corrective Actions (Element 7)

2. Procedure(s) will be revised to include component repair, component replacement, performance of a more rigorous analysis, performance of an ASME Code, Section XI, Appendix A or L flaw-tolerance analysis, or scope expansion that considers other locations with the highest expected CUF_{en} values, as corrective action considerations when a cycle counting surveillance limit is exceeded.

3. Procedure(s) will be revised to require that when a cycle-counting surveillance limit is reached, action will be taken to ensure that the analytical bases of the high-energy line break (HELB) locations are maintained.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fatigue Monitoring* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2013, Engineering identified that several thermal transients had occurred in the past during the performance of a surveillance test procedure for safety injection (SI) system valve leakage testing. The surveillance test was performed following each refueling outage prior to entering Mode 2. Addition of these previous thermal transients into the thermal monitoring program increased the cycle count for the SI nozzles to 73. An evaluation projected that the SI nozzles CUF would remain below 0.70 for 60 years of plant operation. The Nuclear Regulatory Commission (NRC) was notified (ADAMS Accession No. ML13225A006). Additional non-destructive examinations were performed for the reactor coolant system cold leg SI piping A, B, and C areas susceptible to thermal stratification. The examination results were deemed acceptable.

   Subsequently, the NRC approved a license amendment request allowing the reactor coolant system pressure isolation valve leakage test to be extended to a performance-based frequency, thereby minimizing the frequency of thermal transients (ADAMS Accession No. ML19023A420).

2. The year-end cycle counting reports for 2017 and 2018 demonstrated that the required fatigue transients were being monitored, that no cycle count limits had been exceeded, and that no CUF to-date values had exceeded the design limit of 1.0. This included the transients listed in the Technical Specifications and the FSAR, as well as additional transients identified in the equipment and piping specifications for the reactor coolant system that were used in the fatigue analyses.

   In September 2021, a gap was identified in the implementation of the *Fatigue Monitoring* program because the year-end cycle-counting reports for 2019 and 2020 had not been completed. An entry was made into the Corrective Action Program to document the occurrence. The 2019 and 2020 year-end reports were subsequently completed, and both reports confirmed no cycle limits or CUF limits had been approached or exceeded. The 2021 year-end report was subsequently completed. The review of the 2022 year-end report is in progress as of summer 2023.

3. In February 2019, during the yearly evaluation of operational cycles and transients, the 2018 transient history report indicated a high number of severe thermal cycles in the steam generator feedwater nozzles during the previous refueling outage. Upon investigation, it was determined that the thermal cycles were being reported due to conservative temperature assumptions in the cycle counting software program. Engineering determined there was no actual fatigue impact to the feedwater nozzles. An upgrade to the software program released in October 2021 addressed the issue by revising the logic to prevent recurrence.

The above examples of operating experience provide objective evidence that the *Fatigue Monitoring* program includes activities to identify and manage fatigue of mechanical or structural components that have a fatigue TLAA or other analysis based on the number of occurrences and severity of transient cycles within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fatigue Monitoring* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fatigue Monitoring* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Fatigue Monitoring* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B3.2 Neutron Fluence Monitoring

Program Description

The *Neutron Fluence Monitoring* program is an existing condition monitoring program that manages loss of fracture toughness due to neutron fluence of the reactor pressure vessel (RPV) regions for which neutron fluence is projected to exceed 1×10^{17} n/cm^2 (E > 1 MeV) during the subsequent period of extended operation to ensure that applicable reactor pressure vessel neutron irradiation embrittlement analyses will remain within their applicable limits.

The program includes provisions to calculate and evaluate RPV neutron fluence projections for the RPV beltline and extended beltline; withdraw and evaluate ex-vessel neutron dosimetry (EVND); use the calculated fluence projections as inputs to perform pressurized thermal shock (PTS) assessments in accordance with 10 CFR 50.61; calculate pressure/temperature (P-T) limit curves; evaluate cold overpressure protection; assess upper shelf energy (USE) in accordance with 10 CFR 50, Appendix G; and track/project effective full-power years (EFPY) for P-T curve applicability.

The methods and assumptions for determining RPV neutron fluence for the beltline region are consistent with NRC Regulatory Guide (RG) 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.”

For the extended beltline region (materials outside the RPV beltline region that are projected to exceed 1×10^{17} n/cm^2 (E > 1 MeV) during the subsequent period of extended operation), the methods, assumptions, and results of neutron fluence calculations are described in WCAP-18709-NP, “V.C. Summer Unit 1 Subsequent License Renewal: Reactor Pressure Vessel Extended Beltline Neutron Exposure Evaluation.” In the plant-specific WCAP, the guidance of RG 1.190 was followed for the neutron transport and dosimetry evaluation methodologies.

The methods used to develop the calculated pressure vessel fluence in the plant-specific WCAP are consistent with the methodology described in WCAP-18124-NP-A, “Fluence Determination with RAPTOR-M3G and FERRET” (ADAMS Accession No. ML18204A010). There is enough margin in the extended beltline material fluence evaluation to demonstrate that the extended beltline materials, including the nozzles, will not become limiting during the subsequent period of extended operation. The controlling materials for PTS, P-T Limit curves, and USE continue to be the beltline materials.

During the development of reactor vessel internals aging management guidance for reactor vessel internals (RVI), the Electric Power Research Institute Materials Reliability Program (MRP) conducted an expert panel to evaluate the neutron fluence impacts on the susceptibility of RVI components to neutron radiation damage mechanisms (including irradiation embrittlement, irradiated-assisted stress corrosion cracking, irradiation-enhanced stress relaxation or creep and void swelling or neutron induced component distortion). A gap analysis evaluated the impact of

“Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines, (MRP-227, Revision 1-A),” inspection recommendations for the subsequent period of extended operation. The gap analysis included plant-specific 80-year neutron fluence values for RVI components that were calculated using a plant-specific RVI component model, and a plant-specific core neutron source conforming to RG 1.190. The 80-year plant-specific neutron fluence values for RVI components were evaluated using the material-specific degradation thresholds in the RVI gap analysis. Ongoing inspections of RVI components for the above radiation damage mechanisms and associated degradation thresholds are performed consistent with the *PWR Vessel Internals* program (B2.1.7).

During the Spring 2005 refueling outage (RF15), the last in-vessel surveillance specimen (capsule) was removed, placed in storage, and remains available for future use. Following removal of the last in-vessel surveillance capsule, new dosimetry capsules were installed exterior to the reactor vessel (ex-vessel) for the measurement of neutron exposure. At least every 10 years, ex-vessel neutron dosimetry is removed, tested and the neutron fluence determined. That neutron fluence value is then compared to the neutron fluence in the current licensing basis (CLB), thus ensuring the validity of the CLB. In 2016, during the Cycle 22 refueling outage (RF23), ex-vessel neutron dosimetry was removed, tested and evaluated. WCAP-18146-NP, Revision 0, “Ex-Vessel Neutron Dosimetry Program for Virgil C. Summer Nuclear Station Unit 1 Cycles 17 through 22,” provides a summary of that evaluation and is the current EVND.

Excluding the RPV nozzle regions, the measured neutron fluence was evaluated at the RPV beltline, found to be acceptable, and based on RG 1.190, the uncertainty requirements in RG 1.190 were met.The capsule stored in the spent fuel pool will be put back in the reactor vessel during the Fall 2027 refueling outage (RF30), irradiated until the Fall 2039 refueling outage (RF38), and then withdrawn and tested to obtain properties for 80 or 100 years of plant operation.

The *Neutron Fluence Monitoring* program is implemented as a Fleet program at Dominion. The program requirements and implementation procedures used across the fleet have been previously reviewed and evaluated by the NRC Staff and determinations were made for Surry Power Station (ADAMS Accession No. ML19360A020) and North Anna Power Station (ADAMS Accession No. ML21354A196) that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The *Neutron Fluence Monitoring* program is an existing program that is consistent, with exception, to NUREG-2191, Section X.M2, “Neutron Fluence Monitoring,” as modified by SLR-ISG-2021-02-MECHANICAL, "Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance."

Exception Summary

The following program element(s) are affected:

Scope of Program (Element 1); Preventive Actions (Element 2); Parameters Monitored / Inspected (Element 3); Detection of Aging Effects (Element 4);and Monitoring and Trending (Element 5)

1. NUREG-2191 specifies that neutron fluence levels in specific components are monitored to verify component locations within the scope of this program are identified. Changes in the neutron fluence levels of the reactor vessel internals (RVI) components within the scope of this program will not be monitored during the subsequent period of extended operation.

Justification for Exception

NUREG-2191, Section X.M2 states that the use of RG 1.190-adherent methods to estimate neutron fluence for RVI components may require additional justification, even if those methods were approved by the NRC for RPV neutron fluence calculations. The technical justification for use of RG 1.190-adherent methods to estimate neutron fluence for RVI components is documented in WCAP-18353-NP, “Reactor Internals Fluence Evaluation for a Westinghouse 3-Loop Plant with Two Units–Subsequent License Renewal.” WCAP-18353-NP contains details that meet the NUREG-2191 Element 3 components. Specifically, determination of the geometrical and material input data for the reactor core, vessel and internals, and cavity; determination of the characteristics of the neutron flux emitting from the core; transport of the neutrons from the core to the vessel, and into the cavity; and WCAP-18353-NP, Table 2.5-1 and Table 2.5-2, which document the figures of merit and power densities of a dual-unit Westinghouse 3-loop upflow plant that utilizes low-leakage core loading patterns for the purpose of MRP-227-A applicability evaluation. The analysis results presented in Table 2.5-1 and Table 2.5-2 of WCAP-18353-NP assumed Unit 1 Cycle 21 through Cycle 24 and Unit 2 Cycle 20 through Cycle 23 had a rated power of 2940 MWt.

Virgil C. Summer Nuclear Station Unit 1 is a Westinghouse three-loop upflow design that uses a low-leakage loading pattern and has a rated power of 2900 MWt, making it similar to the Westinghouse 3-loop plant analyzed in WCAP-18353-NP, except with lower rated thermal power and therefore, lower neutron fluence. This reactor vessel and core geometry with upflow, low leakage core loading pattern, and lower thermal power is effectively bounded by the higher neutron fluence for the reactor vessel internals analyzed for the selected Westinghouse 3-loop plant in WCAP-18353-NP.

As demonstrated in WCAP-18353-NP, the neutron fluence for the selected plant with rated power of 2940 MWt is below the threshold at which visible radiation-induced aging effects are expected for reactor vessel internals. This justifies the exception to NUREG-2191, Section X.M2, Elements 1-5 to not use dosimetry to monitor neutron fluence exposure to reactor vessel internals directly, but instead perform visual inspections of the internals at the 10-year ISI intervals. Inspections are performed per ASME Section XI and MRP-227. Other methods are used in addition to VT inspection; the hold down spring is measured for creep and baffle bolting is UT inspected. Other than baffle bolt degradation, prior RVI visual inspections during 10-year ISI intervals have revealed no visible damage to RVI components from exposure to neutron fluence. The design of the capsule program is per the edition of ASTM E 185 at the time the vessel was stamped/fabricated. ASTM E 185 does not require dosimetry for the internals.

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Neutron Fluence Monitoring* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2004, the fifth surveillance capsule (Capsule Z) was withdrawn from the reactor vessel at the end of Cycle 14. The Capsule Z examination results report documented that the specimens in Capsule Z were exposed to fluences equivalent to approximately 6.54 $\times 10^{19}$ n/cm^2 based on the calculated fluence. The USE for the reactor vessel materials was estimated for the end of the 60-year period of extended operation, 56 EFPY. The calculated USE values for the limiting reactor vessel material is above the 50 ft-lb minimum required USE value for 56 EFPY. Based upon data from analysis of Capsule Z and updated calculated neutron fluences, revised P-T curves were developed for 56 EFPY. Following NRC review and approval, the revised P-T curves were incorporated into the Technical Specifications, in accordance with 10 CFR 50.
2. During the 2005 refueling outage (RF15), the sixth and final capsule (Capsule Y) was withdrawn and placed in storage for possible future use. Accordingly, ex-vessel neutron dosimetry EVND was installed during RF15 for measurement of neutron fluence required by 10 CFR 50, Appendix H. In July 2007, the EVND was withdrawn and evaluated as described in WCAP-16782-NP, “Ex-Vessel Neutron Dosimetry Program for Virgil C. Summer Nuclear Station Cycle 16”. Using dosimetry evaluation methodologies that follow the guidance of RG 1.190, the Ex-Vessel Neutron Dosimetry from Cycle 16 was analyzed. In addition, the neutron dosimetry sensor sets from the first five in-vessel surveillance capsule withdrawn were re-analyzed using the current dosimetry evaluation methodology. These dosimetry re-evaluations, along with the Cycle 16 Neutron Dosimetry, were then used to validate the calculation models that were applied in the plant-specific neutron transport analyses. Subsequently, in 2016, EVND was withdrawn and analyzed following irradiation during Cycles 17 through 22. WCAP-18146-NP summarized the most recent analyses of the EVND (2016). These dosimetry re-evaluations were then used to validate the calculation models that were

applied in the plant-specific neutron transport analyses. The neutron fluence was calculated and evaluated at the RPV beltline and found to be acceptable and plant-specific calculations meet the uncertainty requirements in RG 1.190.

3. In 2021, a discrete ordinates transport analysis was performed to support the 80-year subsequent license renewal time-limited aging analysis for reactor vessel neutron embrittlement. The analysis was documented in WCAP-18709-NP, “V.C. Summer Unit 1 Subsequent License Renewal: Reactor Pressure Vessel Extended Beltline Neutron Exposure Evaluation.” The neutron transport methodology used to generate the data followed the guidance of RG 1.190 and was consistent with methodology generically approved by the USNRC for calculating exposures of the RPV beltline (i.e., RPV materials opposite the active fuel). Presently, there are no generically-approved methods for calculating exposures of Westinghouse RPV extended beltline materials. To justify the application of this method to the extended beltline, the uncertainty associated with the calculated neutron exposure of the surveillance capsules and reactor pressure vessel beltline was calculated based on the recommended approach provided in RG 1.190. For the plant-specific benchmarking, five in-vessel and six ex-vessel sensor sets were irradiated at the core midplane elevation and subsequently withdrawn for analysis. Four additional ex-vessel sensor sets were withdrawn from axial elevations near the top and bottom of the active fuel. Comparisons of the measurement results from each of the sensor set irradiations with corresponding analytical predictions at the measurement locations were performed. The resulting net calculational uncertainty using the RG 1.190 methodology was 13%.

The above examples of operating experience provide objective evidence that the *Neutron Fluence Monitoring* program includes activities to identify loss of fracture toughness due to neutron fluence for components susceptible to neutron embrittlement within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Neutron Fluence Monitoring* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Neutron Fluence Monitoring* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Neutron Fluence Monitoring* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B3.3 Environmental Qualification of Electric Equipment

Program Description

The *Environmental Qualification of Electric Equipment* program is an existing program that manages equipment thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49 qualification methods. This program implements the environmental qualification (EQ) requirements of EQ Rule 10 CFR 50.49. The EQ Rule specifically requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform applicable safety functions in those harsh environments after the effects of in-service aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

The basis for Equipment Qualification for the original plant design is IEEE 323-1971, "General Guide for Qualifying Class 1E Electrical Equipment for Nuclear Power Generating Stations," and NUREG-0588 Category II requirements, as codified by 10 CFR 50.49. However, some equipment was qualified to IEEE 323-1974, "IEEE Standard for Qualifying Class IE Equipment for Nuclear Power Generating Stations," NUREG-0588 Category I requirements. Electrical equipment for replacements or modifications to the plant is procured under the guidance of 10 CFR 50.49 and is qualified under the requirements of IEEE 323-1974 and NRC Regulatory Guide (RG) 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants." IEEE 323-1974, "IEEE Standard for Qualifying Class IE Equipment for Nuclear Power Generating Stations," provides the criteria for safety-related equipment (electrical Class 1E equipment) and the basis for categorizing components important to safety and defines environmental service conditions. Therefore, the EQ program includes and identifies electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49.

As required by 10 CFR 50.49, EQ equipment not qualified for the current license term is refurbished or replaced, or has its qualified life extended through reanalysis or ongoing qualification prior to reaching the designated life aging limits established in the evaluation. Aging evaluations for EQ equipment that specify a qualified life of 40 to 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 the 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).

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. An acceptable method for establishing the 80-year normal radiation dose is to multiply the 40-year normal radiation dose by two, with the result being added to the accident radiation dose to obtain the total integrated dose for the component. A similar approach may be used for cyclical aging.

Data Collection and Reduction Methods: 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. Temperature data and uncertainties used in an equipment EQ evaluation should be based on plant design temperatures or on actual plant temperature data. A representative number of temperature measurements over a sufficient period of time are evaluated to establish the temperatures used in an aging evaluation. Similar methods of identifying excess conservatism in the equipment service condition evaluation may be used for radiation and cyclical aging. Changes to material activation energy values as part of a reanalysis are justified.

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. Although areas within a nuclear power plant may experience actual ambient environments that are less severe than the anticipated plant design environment, in a limited number of localized areas, the actual environments may be more severe than the plant design environment considered for EQ equipment. These adverse localized environments are addressed in an EQ reanalysis. Accessible passive EQ electrical equipment within the scope of subsequent license renewal will be inspected at least once every 10 years to identify EQ electrical equipment subjected to an adverse localized environment with the first inspection performed prior to the subsequent period of extended operation.

Acceptance Criteria and Corrective Actions: Reanalysis of an aging evaluation can be used to extend the environmental qualification of the equipment. If the qualification cannot be extended by reanalysis, the equipment is refurbished, replaced, or re-qualified prior to exceeding the current qualified life.

When the reanalysis assessed margins, conservatisms, or assumptions do not support reanalysis (e.g.: extending qualified life) of EQ equipment, 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. 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.

NUREG-2191 Consistency

The *Environmental Qualification of Electric Equipment* program is an existing program that is consistent with NUREG-2191, Section X.E1, “Environmental Qualification of Electric Equipment.”

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Environmental Qualification of Electric Equipment* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2014, the station personnel noted a difference in preventive maintenance (PM) intervals for solenoid operated valves (SOVs) on the main steam drain valves. Upon investigation it was noted that six of the SOVs had inspection intervals outside the qualified lives. The six SOVs are normally energized and installed in similar ambient environments. The SOVs were replaced during the Spring 2014 refueling outage (RF21).

   The Equipment Qualification Data Base (EQDB) was updated for two of the SOVs on the main steam drain valves to reflect a 16.9-year qualified life and the PM was updated to change the replacement frequency to 16.5 years. The EQDB was updated for the other four SOVs on the main steam drain valves to reflect a 20.3-year qualified life and the PM was updated to change the replacement frequency to 19.5 years. The PM frequencies were selected to be conservatively less than the qualified lives.

   An extent of condition was performed for similar solenoid valves in the EQ program. Each PM frequency was compared to the EQDB qualified life to verify the PM was conservatively established within the qualified life. The replacement schedules in the EQDB were also compared to the aging calculations. No other discrepancies were found where the PM frequency was longer than the qualified life from the EQDB.

2. In August 2017, a review of industry operating experience identified several occurrences of the re-use of gaskets and O-rings during Namco limit switch maintenance at other nuclear stations. To maintain equipment qualification, the Namco EQ report specifies after switches have been installed and cover plates torqued, any subsequent activity requiring disturbance of the soft seals (e.g.: top cover gaskets, O-rings, boot seals) requires replacement of the disturbed soft parts.

   As a result, the associated station procedure at VCSNS was updated to provide instructions related to gasket/O-ring reuse. To maintain environmental qualification of the Namco limit switch, the procedure now clearly indicates when replacement of the gasket/O-ring is required.

3. In October 2018, the results of a thermal aging calculation prepared to support initial license renewal determined a hermetically sealed connector for an SOV on the post-accident hydrogen removal system had been installed beyond its qualified life. The updated thermal calculation, which accounted for temperature increases above ambient, not previously considered, resulted in a qualified life of 32.3 years that had expired in February 2015. The connector was subsequently replaced during the Fall 2018 refueling outage (RF24).

   An extent of condition was performed. Thermal aging calculations for Valcor and Target Rock solenoid valves and associated hermetic connectors that support the EQ program were updated to ensure that the calculations considered temperature effects from energized equipment.

4. In 2018, the station identified a residual heat removal limit switch that was installed in April 1999 with a qualified life of 17.5 years. However, a PM had not been established for the limit switch when it was installed. Consequently, at the time of discovery, the limit switch had been installed 19.5 years but had reached the end of its qualified life in October 2016. Further analysis determined that the installed limit switch remained functional. The initial aging calculation conservatively assumed a normal temperature of 120°F for limit switch installations inside the Reactor Building, whereas the maximum normal temperature was 117°F at the location the limit switch had been installed. The limit switch was replaced during the Fall 2018 refueling outage (RF24).

   A PM task was created to require replacement of the limit switch every 15 years. An extent of condition was performed, and it was verified that PMs had been established for similar limit switches with a qualified life of less than 60 years.

5. In July 2020, EPRI revised report NP-1558, “A Review of Equipment Aging Theory and Technology.” This nuclear industry source document provides methodology and material activation energy values used as design input to aging calculations evaluating equipment qualified lives and replacement frequencies, as required for EQ Programs to comply with 10CFR50.49. Qualified life results are used to bound replacement frequencies of preventive

maintenance activities. The revision to NP-1558 discovered some original laboratory test data could not be retrieved to support the prior reported material activation energy and therefore was removed in the recent revision. No concern about fraud was identified. Similar material property values are available from other test labs and manufacturers published data that provide similar values; therefore, no significant impact to existing qualified life and maintenance frequencies is expected. The specific materials of concern, where referenced lab test data could not be found, are epoxy, phenolic, DAP, ethylene polypropylene rubber (EPR), nitrile rubber, Hypalon (CSPE), Kapton, Kynar and polyester resins.

Design calculations that identify activation energies used in thermal aging and document the evaluation were reviewed to determine which calculation used EPRI NP-1558 for design input Activation Energy values or identify if no longer used in an active EQDP. This search for materials of concern referencing the original EPRI-1558 identified calculations needing revision.

Impacted calculations have been revised using verified references for the Activation Energy values. No qualified lives were shortened in these evaluations. Reviews were also performed of EQ Program documents: EQ-Design Base Document, EQ guides, and Program procedure. These documents only reference EPRI NP-1558 cited aging methodology which was not changed in this revision and thus are not impacted.

The above examples of operating experience provide objective evidence that the *Environmental Qualification of Electric Equipment* program includes activities to perform audits and document reviews to identify thermal, radiation, and cyclical aging effects for qualified electrical equipment within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Environmental Qualification of Electric Equipment* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Environmental Qualification of Electric Equipment* program will effectively identify aging prior to a loss of intended function. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The continued implementation of the *Environmental Qualification of Electric Equipment* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B3.4 Concrete Containment Unbonded Tendon Prestress

Program Description

The *Concrete Containment Unbonded Tendon Prestress* program is an existing condition monitoring program that manages loss of prestress of the Reactor Building tendons. This program is based on ASME Code, Section XI, Subsection IWL criteria, as supplemented by the requirements of Title 10 of the Code of Federal Regulations (10 CFR) 50.55a(b)(2)(viii).

The program consists of an assessment of measured tendon prestress forces obtained during examinations performed in accordance with the ASME Code, Section XI, Subsection IWL, as incorporated by reference in 10 CFR 50.55a. The program includes confirmatory actions that monitor loss of Containment tendon prestressing forces. Trend analyses of tendon prestress loss will be continued to the end of the subsequent period of extended operation.

The program requires measurement of prestressing forces on an initial, random sample of each tendon group, based on type (dome, hoop, vertical), by performing tendon lift-off force measurements. The measurements are performed every five years, as specified in IWL-2400. In addition to the random sampling used for tendon lift-off force measurement, one tendon in each group and subgroup is selected as a common tendon. The initial sample size, which may be expanded if unacceptable conditions are found such as prestressing force values less than 95% of the predicted lower limit value, is established as specified in ASME Code, Section XI, Subsection IWL, Table IWL-2521-1.

Assessments of the results of the tendon prestressing force measurements are performed in accordance with the ASME Code, Section XI, Subsection IWL, to confirm adequacy of the prestressing forces for each tested tendon. The assessment consists of a comparison of predicted lower limit values to corresponding minimum required prestressing values and the development of the forecasted trend lines based on measured lift-off data. The predicted lower limit value for individual tendons is developed based upon the original design criteria and the current licensing basis for the tendons. These criteria consider the same factors that are described in NRC Regulatory Guide (RG) 1.35, Revision 1, “Determining Prestressing Forces for Inspection of Prestressed Concrete Containments.” The predicted final effective tendon preload is based upon a regression analysis of measured lift-off results for each tendon. Trend analyses of tendon prestress loss will be continued to the end of the subsequent period of extended operation. The acceptance criteria consist of a comparison of the forecasted trend lines to the corresponding tendon group minimum required prestressing values. The forecasted regression data of the trended lift-off results for each tendon are used to verify that the dome, horizontal, and vertical tendons will exceed the minimum required value for their selected group with acceptable margin during the subsequent period of extended operation.

Trend line regression analysis is performed consistent with NRC Information Notice 99-10 (IN 99-10), “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments”, for each tendon group. Trend lines, one for each tendon group, are developed using the measured tendon forces and represent the changes in mean vertical, hoop, and dome prestressing forces with time. The trend line for each tendon group and subgroup is constructed by regression analysis of the individual, measured prestressing forces in individual tendons of that group and subgroup obtained from the previous representative examinations. If the trend lines do not fall below the minimum required prestressing values prior to the next scheduled surveillance, the tendon prestress force is considered to be acceptable. In accordance with the requirements of ASME Code, Section XI, Subsection IWL, in IWL–3221.1(c), if the trend lines predict the prestressing forces in the Containment to be below the minimum required prestressing value before the next scheduled examination, an evaluation would be performed and reported in the Engineering Evaluation Report as required in ASME Code, Section XI, Subsection IWL, in IWL–3300. The evaluation would include identification of corrective action prior to tendon forces falling below the minimum required prestressing value established in the design. Corrective actions may include retensioning of tendons, replacement of selected tendons with new tendons, or reanalysis of the concrete Containment in order to restore the Containment to the required level of structural integrity, prior to a loss of intended function.

Vertical tendon prestressing force examination results, prior to 1990, are not included in the current trend lines since these results no longer represent the trend for the vertical tendon forces. This is due to retensioning of the vertical tendons in early 1990 as described in FSAR Section 3.8.1.6.3.3-8. Measured values for vertical tendon prestressing forces, taken since 1990, have been plotted against time. The dome and hoop tendons have not been retensioned, and measured dome and hoop tendon prestressing forces, since original installation, continue to be plotted against time. Trend analyses of tendon prestress loss will be continued to the end of the subsequent period of extended operation.

NUREG-2191 Consistency

The *Concrete Containment Unbonded Tendon Prestress* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section X.S1, “Concrete Containment Unbonded Tendon Prestress.”

Exception Summary

The following program element(s) are affected:

Monitoring and Trending (Element 5) and Acceptance Criteria (Element 6)

1. NUREG-2191, Section X.S1, Element 5 specifies the estimated and measured prestress forces up to the current examination be plotted against time for each of the vertical, dome, and hoop tendon groups. The *Concrete Containment Unbonded Tendon Prestress* program takes exception to this requirement for the vertical tendon group. The estimated and measured prestress forces from 1990 up to the current examination are plotted against time for the vertical tendons.

Justification for Exception

Early in plant life, the loss in prestress force for the vertical tendons was occurring at a faster rate than originally predicted. As described in FSAR Section 3.8.1.6.3.3-8, to maintain the minimum average required vertical prestress force, the vertical tendons were retensioned in 1990. Retensioning the vertical tendons made the estimated and measured prestressing forces data from prior to 1990 obsolete since these results no longer reflect the vertical tendon prestress force trend. Therefore, plotting the estimated and measured prestressing forces from 1990 up to the current examination against time is justified.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Scope of Program (Element 1); Preventive Actions (Element 2); Detection of Aging Effects (Element 4); and Acceptance Criteria (Element 6)

1. Procedure(s) will be revised to specify that the trend analyses of tendon prestress loss will include trends projected through the end of the subsequent period of extended operation.

Monitoring and Trending (Element 5) and Acceptance Criteria (Element 6)

2. Procedure(s) will be revised to specify that for each surveillance interval, the predicted lower limit, minimum required value, and trending lines will be developed for the subsequent period of extended operation as part of the regression analysis for each tendon group.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Concrete Containment Unbonded Tendon Prestress* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. During June 2011, the eighth tendon surveillance (30th year) was completed.

   In addition to testing a common tendon from each tendon group, an additional two tendons from each tendon group (vertical, dome, and hoop) were randomly selected for testing. The predicted lift-off forces for each tendon were calculated in accordance with RG 1.35, Revision 1 and nine tendons were above 95% of the predicted lift-off force values required by IWL-3221.1(b). Based on the acceptable results, no additional lift-off force measurements were required for adjacent tendons.

   The group average lift-off force for the as-found lift-off values as well as the individual lift-off values were above the required average minimum design forces for the respective tendon group.

   The regression (trend) analyses results, for each of the three tendon groups, using the latest lift-off data as well as the previous lift-off data, showed the trend for the average of the group prestress forces would remain above the required minimum design force beyond the next regularly scheduled surveillance (35th year).

2. In November 2015, the ninth tendon surveillance (35th year) was completed.

   In addition to testing a common tendon from each tendon group, an additional two tendons from each tendon group (vertical, dome, and hoop) were randomly selected for testing. The predicted lift-off forces for each tendon were calculated in accordance with RG 1.35, Revision 1 and the measured prestress forces for eight of the nine tendons were above 95% of the predicted lift-off force values required by IWL-3221.1(b).

   Since the lift-off force of the remaining dome tendon was 93.7% of the predicted lift-off force, the condition was documented in the Corrective Action Program. The Responsible Engineer reviewed the result and determined that this one tendon had a lift-off force below 95% of the predicted lift-off force but greater than 90% of the predicted lift-off force. In accordance with the approved procedure, lift-off forces were measured for the adjacent dome tendons. The lift-off forces for both adjacent tendons were tested and found to be greater than 95% of the predicted lift-off force. The acceptance criterion is that the average lift-off force for both of the two adjacent tendons must be 95% or greater than the predicted lift-off force. As a result, the existing tendon lift-off forces were determined to be satisfactory.

   The group average lift-off force for the as-found lift-off values were above the required average minimum design forces for the respective tendon group.

   The regression (trend) analyses results, for each of the three tendon groups, using the latest lift-off data as well as the previous lift-off data, showed the trend for the average of the group prestress forces would remain above the required minimum design force beyond the next regularly scheduled surveillance (40th year).

3. In May 2020, the tenth tendon surveillance (40th year) was completed.

   In addition to testing a common tendon from each tendon group, an additional two tendons from each tendon group (vertical, dome, and hoop) were randomly selected for testing. The predicted lift-off forces were calculated for each tendon in accordance with the methodology of RG 1.35, Revision 1. The measured lift-off forces for the surveillance tendons were found to be above 95% of the predicted lift-off force values as required by IWL-3221.1 (b).

   The group average lift-off force for the as-found lift-off values as well as the individual lift-off values were above the required average minimum design forces for the respective tendon group.

   The regression (trend) analyses results, for each of the three tendon groups, using the latest lift-off data as well as the previous lift-off data, showed the trend for the average of the group prestress forces would remain above the required minimum design force beyond the next regularly scheduled surveillance (45^{th} year).

The above examples of operating experience provide objective evidence that the *Concrete Containment Unbonded Tendon Prestress* program includes activities to perform assessments of the results of the tendon prestressing force measurements to identify loss of prestress for the Reactor Building tendons, to confirm the adequacy of the prestressing force, and to initiate corrective actions. Occurrences that would be identified under the *Concrete Containment Unbonded Tendon Prestress* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional examinations, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Concrete Containment Unbonded Tendon Prestress* program will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Concrete Containment Unbonded Tendon Prestress* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

Virgil C. Summer Nuclear Station

Application for Subsequent License Renewal

Appendix C

Intentionally Blank

Virgil C. Summer Nuclear Station

Application for Subsequent License Renewal

Appendix C -
(Optional)

Intentionally Blank

Virgil C. Summer Nuclear Station

Application for Subsequent License Renewal

Appendix D
Technical Specification Changes

Intentionally Blank

APPENDIX D

TECHNICAL SPECIFICATION CHANGES

10 CFR 54.22 requires that an application for license renewal include any Technical Specification changes or additions necessary to manage the effects of aging during the period of extended operation.

No Technical Specification changes or additions were identified as necessary to manage the effects of aging during the subsequent period of extended operation and as such, no Technical Specification changes or additions are included with this Subsequent License Renewal Application.

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